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Tar Sands
Field Test
Santa Cruz

Volume 1
Text and Tables

FIELD TEST OF THE LINS METHOD FOR THE RECOVERY OF OIL FROM TAR SAND

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SANTA CRUZ, CALIFORNIA

FIELD TEST OF THE LINS METHOD

FOR RECOVERY OF OIL FROM TAR SAND

by

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Santa Cruz Thermal Recovery Experiment
Santa Cruz, California

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SUMMARY

From February, 1958, until January, 1959, a 100-well test of the LINS method, for the recovery of oil from tar sands, was conducted near Santa Cruz, California. This test covered an area of 1/6 of an acre, to a depth of 50 feet, using a 10-foot well spacing. After operating for eleven months, with an average heat input of 26,000 BTU/burner-hour, the average temperature of the heated volume was 730°F. The total oil production was 2665 bbl. with an average gravity of 27°API, and an average gas-oil ratio of 1695 scf/bbl. Over 9000 bbl. of water were produced because of the large amount of water flowing through the deposit. The overall hydrocarbon yields inside the heated volume varied from 56 to 69% by weight. About 75% of this was produced as oil. There was considerable movement of tar, at temperatures below that required for pyrolysis, however, this, and the high recoveries, may have been aided by the large amount of water in the formation, and the resultant steam flooding of the sand.

INTRODUCTION

Since 1943, a commercial process has been in operation in Sweden to recover oil and gas from oil shale. This is done by heating the deposit to about 725°F with electrical heaters, set in wells through the formation and arranged in a hexagonal pattern with a 7.2-foot spacing. The process is called the Ljungstrom In-Situ (LINS) method.

In 1955, a test program was initiated at Santa Cruz, California, by Husky Oil Company and Svenska Skifferolje Aktiebolaget, with the purpose of adapting the LINS method to tar sand deposits. Gas burners were to be used instead of electrical heaters.

Several burner designs were studied and information was obtained on heat transfer and on the flow of produced fluids in the formation. The results of these tests have been reported previously[1].

Since October 1, 1957, the research work has been continued by Husky Oil Company, Union Oil Company of California and Svenska Skifferolje Aktiebolaget. Burner design, construction materials and oil and gas recoveries from the tar sand have been studied.

This report concerns one phase of this research work, a 100-burner field test of the LINS method, called "Test L9". The principle objective of this test was to obtain information on oil and gas recovery.

1 Persson, B., "Oil Recovery from Tar Sand with the LINS Method - Report of Field Tests at Santa Cruz, California, 1955-1957", September 12, 1958.

DESCRIPTION OF TEST FACILITIES

Tar Sand Deposit

A suitable test area was found on Husky Oil Company's T. E. Majors Lease, about six miles west of Santa Cruz, in the same area as the previous tests. Core drilling, which was done at a number of locations, showed that a fairly uniform tar sand layer existed between 10 and 45 feet depth. The surface was flat but slightly sloping towards the southeast.

A test area of 78 feet x 95 feet, 0.17 acre, was chosen and a more extensive coring program was carried out. The locations of these wells are shown on Figure 1. The well logs are shown on Figures 2 through 13 and summarized in Figure 14 and Table 1. Figures 15 through 23 show tar contents in various depth intervals.

The average tar content between 15 and 45 feet was 11.5 lbs/cu ft of tar sand with a decreasing tar content towards the northwest corner.

The tar sand appeared to be black and hard. There were minor streaks of limestone and soft coarse tar sand and a 5-foot layer of non-bituminous shale between 40 and 50 feet.

The following analyses were made on the extracted tar:

Gravity	4.0° API
Viscosity	36,830 SSU at 275°F
Nitrogen	1.52% (wt)
Carbon Residue	25.8%
Sulfur	2.86%

Burner-Gas Wells

The burner-gas wells were of two types. In 97 of them a 52-foot long, 2-1/2-inch burner casing was inside a 4-inch gas casing, which extended from the surface to a depth of 13 feet. The well fluids were produced through the annulus between the casings. In three of the burner wells a 13-foot long, 1-1/2-inch gas casing was placed alongside the burner casing. These latter wells also contained a 52-foot long, 1-inch pipe welded to the burner casing to serve as a temperature well. The burner wells were placed in a triangular pattern with a 10-foot spacing. They were arranged in 10 rows with 10 burner wells in each row as shown in Figure 24. The rows were numbered from 1 to 10 and the burner wells in each ran from 1 to 10 starting from the southeast corner. Each burner was therefore given two numbers with the letter B for burner. Thus B3-4 means the fourth burner in the third row.

The burner casings were made of 5% chromium and 1.5% silicon alloy steel and the gas casings of carbon steel.

Burners

The burner consisted of a supply tube made of 1/2-inch and 1/4-inch pipe, a 1/4-inch x 1-inch conical enlargement (burner cone) and a 20-foot burner tube made of 1-inch tubing. The 1/2-inch supply tube was carbon steel and the other burner parts were made of various types of stainless steel.

Through the supply tube the fuel-air mixture entered the cone, which acted as a flame-holder. The burner tube conducted the exhaust gas to the bottom of the burner casing, from where it ascended through a fluidized sand bed in the annulus between the burner and the burner casing. The exhaust gas was released to the atmosphere at the well-head. The fluidized sand acted as a heat-transfer medium to provide uniform heat distribution along the burner casing.

A nominal 8-12 mesh commercial grade sea sand was used. The settled sand bed was 12 to 14 feet high in the annulus and expanded when fluidized to a height of 30 to 35 feet.

Schematic drawings and detailed descriptions of the burner wells are shown on Figures 25 and 26 and Table 2.

Separate Gas Wells

Besides the burner-gas wells, twenty three separate gas wells were drilled, fourteen to a depth of 20 feet and nine to 50 feet. The latter ones were refilled to 15 feet with coarse gravel. All were equipped with 15 feet of 1-1/2-inch casing. Schematic drawings of the wells are shown on Figure 26 and detailed descriptions on Table 3.

The locations of the separate gas wells are shown on Figure 24, marked with a letter G and a number, corresponding to the nearest burner well number. Fifteen of the wells were drilled at the point midway between three burner wells and the other eight were drilled 2 feet from a burner well.

Temperature Wells

Besides the three temperature wells along burner casings, there were twenty two temperature wells with casings of 2-1/2-inch carbon steel pipe to a depth of 52 feet. These temperature wells are shown on Figures 24 and 27, marked with a T and a number, corresponding to the nearest burner well number. There were fourteen wells placed at the midpoint between three burner wells, three wells located 3 feet from a burner, one well 4 feet from a burner, and four wells located 10 feet outside the test area.

The temperature was measured with a thermometer placed in a 1-foot long holder made of two concentric pipes welded together on top and bottom. By means of a cable and a reel the thermometer holder could

be placed at any depth. Because of the heat capacity of the holder the formation temperature could be read with sufficient accuracy when the holder was brought up to the surface.

Water Wells

To remove ground water before and during the test, fourteen water wells were drilled to depths between 55 and 75 feet and equipped with air powered piston pumps. Five of these wells were located inside the test area, as shown on Figure 24, and nine were 12 to 20 feet outside the test area, as shown on Figure 27. All are marked with W and a number, corresponding to the nearest burner well number.

A schematic drawing and a detailed description of the water wells are shown on Figure 26 and Table 4.

Fuel Gas System

The propane-air mixture was distributed to the burners at a pressure of about 28 psig. The fuel distribution lines are shown on Figure 28. Orifices at the top of each burner supply pipe regulated the rate of flow, thus maintaining a uniform supply of fuel gas around the field. The air was compressed to 33 psig by a Fuller rotary compressor (Type C-100), with a 90°F aftercooler. This compressor has a capacity of 450 cfm. Three reciprocating compressors were used for utilities air supply and as stand-by capacity. The propane rate was controlled by a Honeywell ratio controller at the stoichiometric ratio of 24:1. The propane storage was kept at about 60 psig by two pressure controlled vaporizors. The above equipment, which is shown on Figure 29, was located about 100 feet from the test area.

Production Handling and Storage

The produced fluids were collected in a system of lines (shown on Figure 28) leading to the condensing and separating equipment (Figure 30). This was of conventional type and included a primary separator, treater, condenser, secondary separator, and a gas sweetener.

The oil was gauged every day in the oil tanks. The water was measured with a dump type meter until 4,150 hours from start, and thereafter the water was collected and gauged in a tank. The gas was measured with a recording orifice meter and then flared.

OPERATION OF TEST

Heat Inputs and Burner Positions

The heat input was calculated daily from the air and propane flow rates, which were measured three times daily. In addition, the ratio controller recorded these rates continuously on a weekly chart. The heat input data in this test were based on the gross heat of combustion of propane of 2,512 Btu/scf, or 105.5 Btu/scf of air. The combustion efficiency was determined by a weekly Orsat analysis of the exhaust gas. Two mass spectrometer analyses of exhaust gas are shown on Table 5.

During the test, the heat input varied from 17,000 to 30,000 Btu/burner-hour, with an average of 26,120 Btu/burner-hour. Figure 31 shows the heat inputs and number of burners in operation each day during the test. The cummulative heat input is shown on Figure 32. Table 6 shows the total heat input for each burner during the test. These heat inputs varied from 150 to 210 million Btu/burner, the average being 196 million Btu.

The first four rows of burners were started on February 25, 1958. Rows 5 to 8 were started 506 hours later on March 18, and the last two rows on March 26, at 698 hours. The burners were originally started at 28,000 Btu/burner-hour with the cone at a depth of 28 feet and the burner tube extending to 48 feet. When the last two rows of burners were started at 698 hours, the heat input dropped to 25,500 Btu/burner-hour because of a lack of sufficient compressor capacity. At about 1,800 hours, a second compressor was added and the heat input increased to 30,000 Btu/burner-hour. The heat input varied at this time from 28,000 to 30,000 Btu/burner-hour because of variations in the air-propane mixture and variations in the temperature at the compressor inlet.

At about 2,400 hours, early in June, the heat input was decreased to about 28,000 Btu/burner-hour. This was done because the sand losses appeared to increase erratically at inputs above 29,000 Btu/burner-hour. A week later, at about 2,550 hours, the sand level was also decreased to 9 feet of burner casing, which in turn caused the height of the fluidized sand bed to decrease by about 3 feet. The overburden, which was composed mostly of tar sand, was being overheated and the resultant softening had caused gas leaks to develop. During the period from June to September (2,500 to 5,000 hours) the burners were operated at the above conditions, i.e., 28,000 Btu/hour and 9 feet of sand. In September it again became apparent that the overburden was being overheated, and in addition, coke was forming in the gas casings. In order to lower the heated interval, the burner tubes were shortened from 20 to 17 feet in length and the cones were placed at a depth of 33 feet. The same sand level, 9 feet of burner casing, was maintained. Under these conditions the heated interval extended from 18 to 50 feet from the surface. On September 27, at 5,140 hours, the heat input was decreased to 25,000

Btu/burner-hour. The safe operating temperature for the casing was 1,200°F, and this temperature had been reached in several of the burners. The temperature continued to increase, but at a slower rate, and on November 3, at about 6,000 hours, the heat input was decreased even further to 23,000 Btu/burner-hour, and the sand level was decreased to 8 feet of burner casing. Because of edge heat losses, the flow of formation water, and the original start-up schedule, the hottest burners were the inside burners in Rows 3 to 5, i.e., B3-2 to 9, B4-2 to 9, and B5-2 to 9. Therefore, on November 24, at 6,550 hours, smaller orifices were placed on these burners and their heat inputs were changed to 21,000 Btu/burner-hour. The remaining burners were operated at 26,000 Btu/burner-hour, and the sand level in all burners was changed back to 9 feet of burner casing. The inside burners were not only run at a lower heat input but, because of the reduced expansion of the sand bed, the heat was concentrated mainly in the lower half of the formation. On December 9, at 6,900 hours, new orifices were put in the inside burners and their heat inputs were lowered further to 17,500 Btu/burner-hour. The burners operated under these conditions, 26,000 and 17,500 Btu/burner-hour and 9 feet of sand, until they were shut off on January 27, 1959, at 8,057 hours.

Sand Losses

The amount of sand in the burner casings was checked every three to five days, and the original sand level was restored by adding sand of the same type as that originally used. The sand level was measured by pulling the burner out of the sand, allowing the sand bed to settle in the bottom of the casing, and setting the bottom of the burner on the top of the sand bed. This measured height was referred to as the sand level in "feet of burner casing".

Sand losses during the test are shown on Figure 33. As shown on this figure, the burners were started with 10 feet of sand. At about 1,800 hours, when the heat input was increased from 25,500 to 30,000 Btu/burner-hour, the sand losses began to increase and at about 2,400 hours were averaging 0.4 feet/day. There was considerable variation in these data with some wells losing as much as 1 foot/day. With high sand losses there was a possibility of the sand bed being too small to cover the burner cone and thus causing the cone to become overheated. Therefore at 2,400 hours the heat input was decreased to 28,000 Btu/hour and the sand losses then decreased to about 0.35 feet/day. Figures 34 to 36 show that at this time the temperature at 12 feet was from 500 to 550°F and increasing at a fairly constant rate. In order to avoid overheating the overburden, an attempt was made to lower the heated interval, by decreasing the sand level from 10 to 9 feet, on June 10, at about 2,525 hours. The burners were run at this level until September, at about 5,140 hours, when the burners were lowered and the heat input decreased to 25,000 Btu/hour. During this period, from June to September, the sand losses continued to increase, reaching a peak value of 0.65 feet/day. Although the purpose of this test was to obtain production data, some work was done to reduce sand losses. It was concluded at this time that the sand losses were due mainly to the slugging of the sand bed, and because there was insufficient

disengaging space above the bed, little could be done to decrease the losses. Baffles were placed on the supply pipes in the first row and part of the second row to break up the slugs, but they appeared to have an insignificant effect on losses.

In September, between 4,440 and 4,850 hours, the burner cones were lowered 5 feet and the burner tube shortened by 3 feet. This lowered the sand level by 2 feet but the sand loss remained constant at about 0.6 ft/day. When the heat input was decreased to 25,000 Btu/burner-hour on September 27, at 5,140 hours, the sand loss dropped to 0.4 feet/day.

Because the gas casings and the overburden were still being overheated, some tests were made, at about 5,500 hours, by running two burners with reduced sand levels to see if the sand height could be decreased. Figures 37 and 38 show the temperatures taken in these burner casings with sand heights of from 5.7 to 9 feet of burner casing. From these data it was apparent that the burner would operate satisfactorily with as little as 6 feet of sand. Therefore, it was felt that a normal sand level of 8 feet should be maintained, allowing 2 feet for sand losses. On November 3, at 6,000 hours, the sand level was decreased to 8 feet and the heat input was decreased to 23,000 Btu/burner-hour. This caused the sand loss to drop as low as 0.3 feet/day. In the last two months of the test, when the burners were run at two heat inputs, the sand level was again maintained at 9 feet and the sand losses were 0.65 feet/day and 0.1 feet/day at 26,000 and 17,500 Btu/burner-hour, respectively.

There was no particular relationship between heat input and sand loss except that higher heat inputs resulted in higher sand losses. However, sand losses also appeared to increase with time, probably due to the wearing of the sand grains and the increasing temperature of the exhaust gases. As the gas became hotter, its viscosity increased and this may have resulted in more pronounced slugging of the sand bed. The sand loss problems in this test were probably more severe than those which would normally be encountered because of the short disengaging space above the sand bed.

Materials of Construction

The main purpose of this test was to obtain recovery data, rather than information on burner operation and materials of construction. Therefore, the materials of construction were selected to give trouble-free operation and were not necessarily the most economical or practical choices.

All of the casings were made of carbon steel except the burner casings. The burner casings were 2-1/2-inch, schedule 40 pipe made of a 5% chromium, 1.5% silicon, 0.5% molybdenum alloy which is described in more detail on Table 7. The suggested maximum operating temperature for this material was 1,400°F. Six of the casings, B4-9, B5-4, B7-3, B8-6, B9-8, and B10-2, failed. In each case except B4-9 this

was caused by a burner failure and these should not be considered as casing failures. The casing in B4-9 failed shortly after the burner was shut off (8015 hr.), probably because of the thermal stress when the casing cooled. This was the only case of a failure under these conditions and it is likely that the casing had previously been weakened by some unknown factor. After the conclusion of the test, attempts were made to recover 14 of the burner casings. Only seven of these could be pulled and these required from 2 to 6 hours each. Most of the time and difficulty was caused by the "make-shift" equipment which was used. With proper equipment, the casings could probably have been pulled in one-half hour. The equipment consisted of two 50-ton hydraulic jacks, a spider, and slips. An extension pipe was welded on the casing so that it extended about 3 feet above the ground surface. Six of the seven casings which could not be pulled broke off at this weld and one broke at the weld 20 feet from the surface. The casings had a yield point of 90,000 lbs and an ultimate strength of 140,000 lbs, however the weakest point was usually the weld at the surface extension pipe. Some of the casings which were pulled were measured, and they showed no reduction in wall thickness or diameter, although there were several layers of scale on the outside surfaces.

The materials used in the burners, as well as the casings, are shown on Table 2. The burner failures are described on Tables 8 and 9. The four 1/4-inch supply pipe failures can be attributed to ignition of the gas in the supply pipe when the flow rate became too low to keep the flame in the cone. This was generally caused by the supply pipe or orifice becoming partially plugged with dirt. The cause of two of the cone failures is not known. However, the failure of the cone in B10-2 was caused by overheating during a period when the sand didn't cover the cone. The burner and casing in B7-3 were overheated when air was injected in the gas casing at an excessive rate, when burning out the coke in the annulus.

The burners were inspected occasionally to check on wear and prevent failures. These inspections are described on Table 10. Usually there was a considerable amount of wear on the supply pipe, couplings, and the centralizers. Six of the supply pipes broke off during the test because of erosion. After the first burner inspection, wear rings were placed on all couplings and above the weld between the supply pipe and the burner cone. The wear at these points, as well as the centralizers, was much more severe on the top than on the bottom of the part. Several couplings had to be replaced and after 4,500 hours most of the top centralizers and many of the middle centralizers were eroded off. These centralizers were originally 2 inches long, however, the replacements were made 6 inches long to give a longer service life. The burners were inspected again after the end of the test and the upper centralizers had been worn down about two inches. Thus they lost about one inch of metal for every 2,000 hours of operation. There was also some evidence of corrosion or erosion on the portion of the burner tube which was within two inches of the cone. This material was 25-20 stainless steel.

Burner Down-Time

The heating time lost, when the burners were off, amounted to 22,781 burner-hours, or 2.95% of the total heating time. The entire field was shut down 1.08% of the time because of power failures, maintenance and repairs on the fuel gas system, and one fuel line explosion. The remaining 1.87% was the time that individual burners were off for repairs, maintenance and unknown reasons. These data are summarized on Tables 11 and 12, and presented in detail on Tables 13 through 18. Figure 31 also shows the number of burners in operation each day. Included in the 22,781 hours that the burners were off was 8,771 hours, or 39%, which could be considered as specific to this test, i.e., because of power failures, an explosion, ground leaks, bushing leaks, and plugged gas wells.. This time was lost because of the low over-burden and other factors which should be eliminated in future tests.

The burners were off for unknown reasons 0.2% of the time. Apparently this was caused by water in the fuel lines. The water apparently collected in the lines until a small quantity would be carried with the fuel gas into a burner. The flow rate to each burner was regulated by a 0.1-inch orifice, which became momentarily blocked when the water reached it. If this didn't extinguish the flame, then the increased vapor velocity, when the water was vaporized, did. In the later stages of the test, when the burners were at temperatures above 1,000°F, they usually relit themselves when the fuel gas resumed flowing. A relatively small amount of heating time was lost because of the burners going out, however, a large amount of the operator's time was involved in checking to see if burners had gone out and in relighting them.

Burner Casing Temperatures

As has been mentioned previously, three of the temperature wells in this test were actually temperature casings welded alongside the burner casings in B3-5, B3-8, and B5-5. Temperature data were taken in these casings on the same schedule as the other temperature wells, usually twice each week. These data are shown on Figures 34 through 41. Also presented on these figures, and on Figures 42 to 46, are temperatures which were taken occasionally inside the burner casings.

The recommended maximum temperature in the casing was 1,400°F, although usually the casings were at 1,200°F or lower to provide an allowance for malfunction of the burner. As can be seen on Figures 39 to 41, this temperature had been reached by 4,000 hours. Subsequent adjustments in heat input and sand level were intended to maintain temperatures no higher than 1,200°F. Temperatures taken in the temperature wells outside the burner casings were 150 to 300°F lower than those in the burner casings.

The gas casings extended to a depth of 13 feet from the surface, and to avoid thermal cracking in the casing, it was desirable to keep these temperatures below 700°F. As can be seen from Curve No. 2 on Figures 34

to 36, the temperature at a depth of 12 feet was never greater than 700°F. The data on Figures 37 and 38 show that a slight adjustment in the length of the heated interval could be made by changing the sand level in the burner casing.

The temperature of the exhaust gas escaping to the atmosphere was about 300°F, as shown on Table 19. At a depth of 14 feet the exhaust gas temperature was usually about 800°F. Below this point, the heat transferred to the casing was considered as heat to the formation, while above 14 feet it was considered as heat to the overburden. Thus, 13% of the heat was lost to the atmosphere, 11% was transferred to the overburden, and 76% was transferred to the tar sand formation. The average heat inputs for this test, when distributed according to the above percentages, are 205 Btu/ft-hr from 0 to 14 feet, and 580 Btu/ft-hr below 14 feet. All the calculations presented above are based on the gross heat of combustion of propane at 65°F.

Tar Sand Formation Temperatures

Temperatures were usually measured in all the temperature wells twice each week. These data are summarized in Figures 47 through 87. The locations of these wells are given on Figures 24 and 27.

In several wells, the temperature data show that water was present in the lower part of the interval. This is indicated by temperature plateaus at the boiling point of water, particularly in the data taken after the burners were shut off, in Figures 48 through 68. In Figures 69 through 87, there is a period of constant temperature at various depths, usually between 1,000 and 4,000 hours. The data taken after the burners were shut off show that water was present in all parts of the field, while the data taken during the heating period show more evidence of water around the edges of the test area, particularly on the north side. Thus it is likely that the water was flowing up from underlying sands, instead of in a horizontal direction through the test interval.

On Figure 80, there is a sharp drop in temperature in well T68 at 4,500 hours. At this time there were surface leaks in this area, and apparently reservoir fluids, particularly water, were flowing up in the annulus between the well and the temperature casing. (This annulus was packed with sand when the casing was set.) When the flow stopped, the temperature rose abruptly to the previous value, indicating that only the temperature well had been cooled down while the formation remained at about 500°F.

Average formation temperatures at 28 feet and between 14 and 42 feet are shown on Figure 88. Also on this figure is the calculated temperature for a field where the burners are assumed to be a large number of infinite line sources, emitting 500 Btu/ft-hr. These temperatures were all measured, or calculated, at a point midway between three burner wells, and do not include the temperature wells along the

edges of the field. The average formation temperature was about 20° higher than the temperature at the midpoint. During the period from 2,000 to 4,500 hours, the temperature rise at 28 feet appears to be equivalent to that which would result from a 500 Btu/ft-hr source. The apparent drop in heat input at 1,500 to 2,000 hours is probably due to the water in the formation being vaporized at this time. After 5,000 hours, edge losses and the decreases in heat input resulted in a decreased slope in the temperature curve. If the final 14 to 42-foot temperatures are compared with the 500 Btu/ft-hr line, it can be seen that these temperatures would have resulted from a heat input of 230 Btu/ft-hr, if there had been no losses and no vaporization of water in the formation. However, the actual heat input, through the burner casings, was 580 Btu/ft-hr. This leaves 350 Btu/ft-hr which can be attributed to losses and vaporization of water. About 1/3 of this was required to vaporize the produced water.

When the burners were shut off, at 8,057 hours, the average temperature in the interval from 14 to 42 feet, in the temperature wells, was 710°F. The average formation temperature was about 730°F with peak temperatures, in the temperature wells, of 815°F.

Heat Balance Over Test Area

A heat balance for the test is shown on Table 20 and Figure 97. In this balance, the heated formation is considered to be the volume between a depth of 14 and 42 feet and enclosed by the second row of wells from the outside of the area. The heat content of the tar sand between the first and second rows of wells, as well as areas outside the field, is considered as lost through the sides of the heated formation. This heat balance shows that only 13% of the heat input remained as sensible heat in the heated area, 44% was lost by conduction, 17% was produced in the oil, gas, and water, 13% was lost in the exhaust gases, and 13% was not accounted for. These losses were unusually high because of the small size of the test area.

Eliminating all losses, 13% of the heat input actually was used to pyrolyze and produce the oil. Assuming 60 to 80% of the oil was produced in the heated formation, as defined above, then the heat used per barrel of oil produced was between 1.2 and 1.6 million Btu/bbl. With an average gas-oil ratio of 1,695 scf/bbl, and an average net heating value of 910 Btu/scf, the heat of combustion of the gas produced with each barrel of oil is 1.54 million Btu/bbl. Therefore, if there were no losses, this test would have produced enough gas to supply the necessary heat during the test.

Safety Hazards

The usual safety hazards, common to any oil production operation, were present in this test. In addition, there were a few which may be unique or of special interest. The propane and air for the burners were mixed in the stoichiometric ratio at the edge of the field, and

the mixture was distributed, through a system of headers and fuel lines, to the burners. Although the ignition point of this mixture is 898°F, there was an explosion on November 17, 1958, at 6,359 hours. The only damage was the breaking of 6 of the 7 rupture discs. This explosion was apparently caused by the oxidation of lube oil, which had accumulated in the fuel lines. At this time the weather was dry and no water was condensing in the fuel lines, and thus the temperature could have built up slowly over a long period of time.

The second major safety hazard was the accumulation of hydrogen-sulfide vapors around the test site. The produced gas contained as much as 14% H_2S, and because of the ground leaks, the H_2S concentration occasionally was high enough to cause nausea and dizziness.

Among other hazards was the possibility of burns while handling hot burners, and the danger of being burned by hot sand which occasionally was blown out of the wells in small slugs. All of these hazards could be overcome by taking normal safety precautions.

PRODUCTION OF FLUIDS

Summary of Test Production

The total production for the 100-hole test was 2,665 barrels of oil, 4,520 mcf of gas, and 8,232 barrels of water. The average gas-oil ratio was 1,695 scf/bbl. These data are summarized on Table 21. The cumulative production is shown on Figure 98 and the production rates on Figure 99. These graphs show that the oil production was not significant until July, 1958 (3,000 hours) and reached a peak of almost 20 bbl/day during October (5,500 hours). Oil production then declined at a rate of 1 bbl/day each week until the end of the test. The burners were shut off on January 27, 1959, (8,057 hours) however, the oil production continued to decline at the same rate for another 1,000 hours.

Gas production increased with oil production, reaching a peak of about 34 mcf/day. The gas-oil ratio reached a peak of 2,500 scf/bbl in December (7,000 hours), and then declined until the test was shut off. These data are also shown on Figure 100, plotted against the average temperature between 14 and 42 feet in the interior temperature wells. It can be seen from this figure that the peak oil and gas production rates occurred when the temperature was at 575 to 625°F. The maximum gas-oil ratio was at 675°F. These curves are not necessarily typical of production inside a large field because of the influence of the edge wells in this test. These edge wells were slower in being heated, because of losses, and therefore they tend to shift the curves to the right, particularly at temperatures above 600°F. The line showing oil production would probably have descended more rapidly, had these edge wells been heated at the same rate as the interior wells. Gas production was affected to a lesser extent because the gas production in the edge wells was never as high as it had been inside the field.

Water production was relatively constant during the test, varying from 20 to 40 bbl/day. Gas-oil ratios and water-oil ratios are shown on Figure 101.

Analyses of Products

The average properties of the gas and oil produced during the test were as follows:

Oil Gravity	27.4°API
Gas Gravity	0.650 (air = 1.0)
Heat of Comb. of Gas	990 Btu/scf (gross)
	910 Btu/scf (net)

The composite gas analysis is shown on Table 22. This table shows that the gas contained about 40% hydrogen, 43% saturated hydrocarbons, 5% unsaturated hydrocarbons, and 9% hydrogen sulfide. Figure 102 shows

the variations in gas density, heat of combustion, and oil gravity (°API) during the test. All of these properties reached their peak values at about 4,500 hours, about 1,000 hours before the peak production rates were attained, and then slowly declined. When plotted against cumulative production, as in Figures 103 and 104, it is seen that the early periods of low gravity and low heat of combustion contributed little to the average values of these properties.

During the period of high gas production, samples were taken, for mass spectrometer analyses, about every two weeks. These analyses are shown on Tables 23 through 30 and Figures 105 through 109. These figures show that the hydrogen increased during the latter part of the test from around 37% to 50%, while methane increased from 26% to 34%, and then decreased rapidly back to 26%. These increases were offset by a decrease in hydrogen sulfide from 13% to 6%, and smaller decreases in the amounts of heavier hydrocarbons. These changes in gas composition generally reflect the increased amount of cracking during the latter stages of the test.

As mentioned above, the oil gravity during the test is shown on Figures 102 and 103. The heavier oil, during the first 3,000 hours, was the result of tar production and the small degree of cracking at this time. Most of the oil was between 24 and 30°API gravity.

Tables 31 and 32 list the analyses of the oil samples. Sulfur content varied from 2 to 2-1/2%, and nitrogen, from 0.30 to 0.44%. The distillations show that the oil had an end point of 910°F in the early part of the test, however, it dropped to 750°F at 6,400 hours. The latter figure is probably more typical of the oil as this sample was taken during the period when oil production was high. The high end point with the earlier sample may have been caused by tar which had been produced and dissolved in the oil. Table 33 shows calculated properties and the analyses of the composite oil.

Post-Heating Core Analyses

Coring Program

The L9 coring program was carried out essentially as originally proposed[1]. Thirty-five core holes were drilled, of which 15 were inside the field, 11 were along the edges, and 9 were outside the field. These locations are shown on Figure 110. Cores were taken to depths of 55 feet.

There were two methods by which the recovery of hydrocarbons could be estimated. One method was to compare the total production of oil and gas from L9 to the volume of tar sand which had been heated. Because of the small size of the test area and the large amount of water present, the temperature profiles were quite complex and therefore it would have been difficult to determine the volume of sand actually heated. In addition, the tar appeared to be moved and pyrolyzed over a wide range

1 Helander, R. E. & Persson, B.,"Proposed Post-Heating Program for Test L9", Santa Cruz Thermal Recovery Experiment, Memo to M. F. Westfall, December 23, 1958.

of temperatures, thus making it difficult to determine the temperature at which tar sand could be considered "heated".

The second method, which was used to calculate recoveries in this test, was to make material balances on small areas inside the field. Three triangular areas were chosen in such a way that there should have been no flow of fluids or heat across their boundaries. Thus each area could be considered as a separate production unit.

Core holes were also drilled along the edges of the field to obtain recovery data at lower temperatures, and to check the possibility of tar movement into or out of the test area. In addition, 6 samples of the overburden were taken to a depth of 5 feet. These were taken in the locations, shown on Figure 110 for core holes 01 through 06, where the leaks were particularly severe.

Core Analyses

The core analyses are shown on Tables 35 through 68 and Figures 111 through 144. The cores were examined visually and broken into 5-foot intervals, each of which was then crushed and mixed. In addition a few inches of each interval were kept intact for bulk density measurements.

The tar and water contents were obtained by extraction in trichloroethylene. Experimental work (see "Studies of Thermal Decomposition of Tar in Tarsand" in the Appendix) was performed which showed that the hydrocarbons which were not dissolved in trichloroethylene consisted mostly of coke. In addition seven samples of coked sand which had been extracted with trichloroethylene were subjected to Fischer Assays. The results of these assays, which are tabulated on Table 34, showed no oil and only very small amounts of gas and water. If the extracted sand appeared to contain coke, then a sample of the unextracted sand was analyzed for total combustible material by a dry ash analysis. In addition the coked sand was analyzed for carbonate, by evolution, to correct for the loss in weight, in the dry ash analysis due to the decomposition of carbonates. The difference between the combustion loss and extractable matter was assumed to be coke.

Recoveries From Inside Areas

Three triangular areas inside the field were cored with five holes each. The average tar contents for each area are shown on Figures 145 through 147. Table 81 shows that the weight percent of the total hydrocarbons produced varied from 56 to 69%, and the volume percent produced as oil varied from 51 to 62%.

The amounts of produced hydrocarbons were obtained by the difference between original and final saturations. The interval from 15 to 45 feet was considered in order to eliminate the soil overburden and the shales which occur

above 15 and from 45 to 50 feet, respectively. The use of this interval also eliminates the fringe areas where the temperatures are lower because of heat losses. These areas contributed relatively little to the overall production.

The production in Area No. 1 may have been affected when the concentric gas casing in well B6-3 was plugged during the month of September, 1958. The average temperature in T62 at this time was from 500 to 580°F. At the time it was not felt that this plugging would affect the ultimate recovery significantly. Subsequent data have shown that there is considerable movement of tar at these temperatures and therefore the recovery may have been reduced by the plugging. This area has the lowest overall recovery (56%). The gas casing was unplugged in October and remained open thereafter.

Area No. 2, near B4-5, was located between two wells which were plugged during the last six months of the test. The recovery data in this area could have been decreased because of the coke formed from tar which flowed into the area. Conversely, the flow of oil from these surrounding areas would tend to dilute and sweep out the tar before it was coked. There were also several serious overburden leaks near this area.

There were no plugged casings or leaks in the vicinity of Area No. 3 (near B7-6).

All of these recovery data were probably affected to the same degree by the steam sweeping tar towards the production casings.

Losses or Gains From Surrounding Areas

Seven holes (C1 through C7) were cored outside the field on the north and south. These core analyses are shown on Figures 111 through 117 and Tables 35 through 41.

Two of the holes on the north side, C2 and C3, showed a slight gain in tar content and two on the south side (C5 and C6) lost a small amount. These changes of less than 1 lb/cu ft are less than the accuracy of the original tar contents. Because of the lack of original cores along the edges of the field, these original tar contents are less reliable and could possibly be in error by 2 lb/cu ft.

Core hole C7 reached a temperature of 420°F and thus the loss of 3.9 lb/cu ft could be explained by flow towards the production well. The other six core holes were at temperatures of 250 to 360°F.

The areas where the material balances were made were inside the field and probably were not affected by tar movement around the edges. Hydrocarbons which were produced through the overburden leaks probably would have been produced in the gas casing in an area where the overburden was tight. Thus it is unlikely that the losses from the test area had a significant effect on the material balances.

Factors Affecting Recovery

Figure 148 shows recovery versus temperature and distance from a burner-production well. These data were taken from Figures 111 through 144. The cores taken in the center of the field were generally at temperatures above 700°F. Therefore, the data were taken from cores along the edges of the field, where the temperatures were lower.

The most significant observation from these data is the high recovery at temperatures as low as 400°F, especially in the upper part of the formation. Laboratory data[1], shown for comparison, show practically no recovery below 500°F. These high recoveries could be due to the lower heating rates or the large amount of steam flowing in the formation. Steam flooding and steam distillation probably contributed greatly to the movement of tar towards the hotter zones near the wells.

The lower recovery in the lower part of the formation is probably due to gravity flow of fluids in the formation and subsequent lay-down of coke. However, the core analyses (Figures 111 through 144) show that generally the original tar content was higher in the lower part of the formation. Figure 149 shows the amount of residual hydrocarbons left in the sand as well as the amount of coke. The difference in the shapes of the coke curves in the upper and lower intervals suggests the gravity flow is an important factor. In the upper interval the amount of coke varies linearly with temperature and distance. In the lower interval, the same type of curve would be expected if there were no gravity flow. However, the lower coke curves show a much sharper coke-temperature relationship, especially close to the well where gravity flow would be the greatest.

The effects of radial distance from the well appear to be quite significant. In the upper interval, the areas removed from the well have the same type of recovery-temperature behavior as a laboratory retort except that recoveries are much higher. As the well is approached the relationship appears to reverse itself. Close to the well, the higher temperature areas actually had lower recoveries due to the increased coke lay-down by fluids flowing toward the gas casing. At low temperatures, the high recoveries near the well could be due to dilution, steam distillation, or steam flooding.

In the lower interval, recovery appears to be proportional to temperature and distance. The lower recovery as the well is approached is probably due to increased gravity flow, as mentioned previously.

Production From Separate Gas Wells

Because of the severe coking in the hot sand near the burner wells, it may be advantageous to use separate gas wells, located away from the

1 Stegemeier, R. J. and Smith, D. F., "Laboratory Studies on Underground Retorting of Bituminous Oil Sands", Union Oil Co. of Calif., Research Dept. Report No. 59-3, January 16, 1959.

burners, instead of concentric burner-gas wells. For this reason, 23 separate gas wells were completed in the test area. For detailed descriptions of these wells see page 4 and Figures 24 and 26.

Twenty of these wells were opened to the production lines at 3,700 hours (July 29, 1958). At this time the average temperature in these wells was 375°F. The remaining three wells were plugged and were never produced. Prior to this time the separate gas wells were opened to the atmosphere occasionally, but they had never shown any signs of producing.

With the exception of the separate gas wells in Row 2 (G22, 24, 26, and 28), the production from these wells was never significant compared to the concentric gas wells. This was probably caused by the lower temperatures and higher saturations of tar and liquids around these wells, i.e., the lower mobility around the separate gas wells would tend to resist the fluid flow towards these wells. The production data are included in Tables 69 through 73.

The wells in Row 2 produced as much as the corresponding concentric burner-gas wells. These wells were located two feet from the burners and were therefore in an area where the mobility of the fluids was high. The wells in Row 9 were also located two feet from the burners; however, these wells never did produce oil at a significant rate.

Four of the water wells (W22, 39, 82, and 99) had concentric gas casings, which were also opened to production at 3,700 hours. Except for W99, the wells had not produced water since 1,000 hours, because the tubings had become plugged with tar. These wells were the best producers in the field. W22, on one occasion, produced oil at a rate of 1.1 bbl/day. The water wells had 50 feet of 1-1/2-inch tubing inside the 15-foot long, 4-1/2-inch diameter gas casing. Otherwise they were similar to the separate gas wells.

The production in water wells probably came through the annulus between the 5-5/8-inch well and the 1-1/2-inch tubing. Temperatures taken in the W22 tubing, from 10 to 45 feet at 6,550 hours, varied between 520 and 580°F. Figure 72 shows that the temperature in T42 varied from 490 to 720°F at this time. This uniform temperature in W22 indicates that there was flow along the tubing at this time.

Two attempts were made to produce a concentric burner-gas well as a separate gas well, by turning off the burner and shutting in the gas casings in the surrounding wells. The first of these was at 5,425 hours (October 9, 1958) in well B5-3. The production declined steadily until a week later when there was only a small amount of gas produced (see Table 69). At this time the burner was restarted and run at a reduced heat input of 12,000 Btu/hr to vaporize liquids which may have condensed in the sand and the gas casing. Four days later the well was completely plugged. The gas casing was later unplugged with compressed air.

Later, at 5,700 hours (October 20), B8-3 was converted to a separate gas well in the same way. As shown on Figure 150, the production increased for 3 days. On the seventh day the production had begun to drop so the burner was started at 12,000 Btu/hr. The production continued to decline until 5 days later when there was none. The gas casing was reopened with compressed air and a week later a 3/4-inch by 8-foot burner was placed in the burner casing with the cone at 9-1/2 feet. This burner was operated at 3,000 Btu/hr to keep the gas casing hot but below the coking temperature of about 650°F. Three days later there was still no production and the gas casing was again opened up with air and the burner was raised to a cone level of 5 feet. In this way the gas casing was heated to temperatures from 500 to 700°F, but there was still no production. Later the 1-inch burner was put back in the well and B8-3 was returned to normal operation at 23,000 Btu/hr. A few days later the well again began to produce. Temperature data taken during this test are shown on Figure 151.

Production Tests at Individual Wells and Production Lines

During the period of declining production rates in November and December, 1958, (6,000 to 7,500 hours) samples were taken occasionally from individual wells and lines. These data are tabulated on Tables 70 through 73. The reason for taking these data was mainly to assist in the operation of the test. They showed also that the water production rates were high around the edges of the field and lower in the center. The data taken in the interior wells is shown on Figure 152 plotted against the average temperature in the temperature wells located in that row. The temperatures in these temperature wells were about 20 degrees below the average formation temperature.

Production of Tar and Emulsions

Because of experiences in previous tests, difficulties were anticipated with the production of tar and heavy emulsions during the early stages of the test. Tar, produced in this state without being pyrolyzed, plugged the 1/2-inch production lines to individual wells, as well as the main lines and the treating and separating equipment. Therefore, before the heating was started, 23°API crude oil from previous tests was injected in each gas casing in the burner-gas wells along with Tretolite and anti-foam agents.

In spite of the above measures, considerable amounts of tar were produced during the first 2,000 hours of the test. In order to dissolve the tar which solidified in the production lines, crude oil, sometimes diluted with diesel oil, was circulated through some of these lines continuously for the first 360 hours. Occasionally these lines became plugged and oil was forced into the gas casings at pressures as high as 25 psig. Therefore continuous circulation was stopped and oil was circulated through the lines 2 to 4 times a day for periods of from 10 minutes to an hour, with the gas wells shut in. There were still many tar plugs and occasionally even the heat

exchangers, separators, and the treater became plugged. A detailed description of these plugs and the oil circulation is given on Tables 74 through 78. Figure 153 shows the number of 1/2-inch production lines plugged with tar.

The tar production occurred mainly in the first four rows while the last two rows had almost no tar production. The main differences in these two areas were the tar contents of 13% and 9%, respectively and the apparently higher water flow in the last two rows. A summary of the tar production data is given below:

ROW	AVG. TAR CONTENT (LB/CU FT)	NO. OF PLUGGED PROD. LINES 1/2-INCH	2-INCH	INJECTION OIL (BBL.)	ADDITIVES	HOURS BEFORE OIL CIRCULATION WAS STOPPED
1 & 2	13.5	96	6	34.8	200 ML ANTIFOAM 200	2190
3 & 4	13	72	7	23.3	450 ML ANTIFOAM 200	2190
5 & 6	11.5	28	2	25.5	800 ML TRETOLITE	1800
7 & 8	10	57	0	24.8	240 ML ANTIFOAM A	1800
9	9	10	0	5.8	NONE	1800
10	9	4	0	0	NONE	1800

From these data it is not apparent whether the oil injection helped or not. Another attempt to prevent tar production was made by increasing the pressure on the production lines. Because of the low thickness of the overburden the pressure was allowed to increase only to 8 psig. As shown on Figure 153, this pressure was reached in production line P2 at 1,775 hours and maintained for 10 days. Thereafter the pressure slowly decreased to 1.6 psig at 3,500 hours. Although the tar production decreased considerably at about 2,000 hours it may have been due to the temperatures in the formation, rather than the increase in pressure. At this time the temperatures at the outside of the burner casings were 500 to 600°F, while temperatures at the gas casings were from 450 to 500°F.

For the first 2,950 hours, the treated oil contained as much as 7% water. Tretolite was added continuously and the treater temperature was kept at 150 to 180°F. The retention time in the treater was about one day. At 2,500 hours the treater was cleaned out and although the excelsior appeared to be clean, it was replaced. After 3,100 hours when the oil gravity was about 23°API the emulsion could be treated satisfactorily and there was no significant amount of water in the treated oil. Toward the end of the test at 6,700 hours an emulsion problem arose again. Water contents in the treated oil were again as high as 7%. The oil at this time was light, 25 to 28°API, and non-viscous, however it appeared to contain about 1% of fine silt or coke particles which apparently held the water in suspension. This oil was finally dried by recirculating tank oil through the treater.

Formation of Coke in Gas Casings

Because of the high temperatures along the burner casings, the annuli between the gas casings and burner casings occasionally became plugged with coke and tar. Curve No. 2 on Figure 153 shows the number of plugged casings, beginning at 4,500 hours, and Figure 154 is a map showing which gas casings were plugged. The casings began plugging at about 4,000 hours, when the temperature at the bottom of the gas casings was in the range of 600 to 650°F. After this time, there were usually about 15 casings plugged at any particular time.

A method was developed whereby the casings were unplugged by burning off the coke with compressed air. Air was injected into the gas casings at rates not higher than 2 cu ft/min until the casing was open. The casing was then shut in and the burner was turned off for a few hours, until the gas casing was cooled down. The casing was then opened to production and the burner relit. This method was successful in most of the casings although there were a few which would become replugged again in a few days. There was also evidence that a few casings were plugged with liquid instead of coke. Four of the gas casings, B3-5, 4-4, 4-6, and 5-6, were probably plugged with cement when attempts were made to seal surface leaks in these areas. The coke plugs indicated that the gas casings should not be heated above 600°F for extended periods of time. This can be avoided either by terminating the gas casing at a shallower depth or by producing through separate gas wells.

Overburden Leaks and Losses to Surroundings

About 2,400 hours after the start of the test, leaks began to appear in the ground surface near a few of the wells. As the test progressed, these leaks became more severe and numerous. The major leaks are shown on Figure 155. Attempts were made to seal these leaks by injecting cement, digging out a hole 3 to 5 feet deep and pouring a concrete plug, compacting the overburden with a pneumatic tamper, and, in one case, by pouring a concrete slab over a group of surface leaks. The most successful method was compacting the overburden, but even this was only a temporary solution. At about 5,500 hours an attempt was made to decrease the losses by decreasing the pressure, however there was no apparent change in the number or severity of the leaks.

These leaks were apparently caused by the softening of the tar sand when it became heated in the overburden, coupled with the damage which was done when excessive pressure was applied to the formation on a few occasions.

It would be impossible to estimate the amount of production lost through these leaks although it was apparently mostly gas and steam. As much as one-fourth of the gas production may have been lost. Samples of the

overburden were taken at six locations, shown on Figure 110 and denoted as O1 through O6. These samples were taken in areas where the leaks were most serious, however they contained no extractable tar, but only iron-sulfide. The iron-sulfide was probably formed by the hydrogen-sulfide in the gas and the iron in the soil. The hydrocarbons which entered the overburden were probably stripped, allowing only the gas, water, and lightest liquids to reach the surface.

Production From Water Wells

During the drilling of the burner wells, it was found that the ground water level varied from 20 to 35 feet. A piston pump was placed in B5-6 and 500 barrels of water were pumped out in 4 days. Figure 156 shows the water levels before and after B5-6 was pumped. This curve shows that the permeability of the deposit to water was fairly uniform.

Because of the high heat of vaporization of water it was desirable to heat as little water as possible. Therefore, five water wells were drilled, at the locations shown on Figure 24, and about 5,000 barrels of water were pumped off before the test was started. As shown on Table 81, these five water wells became plugged with tar during April and May, and were replaced by four more wells, W15, W510, W51, and W105, one on each side of the field, as shown on Figure 27. These four wells, in turn, began to become plugged with tar, particularly on the south and east sides. From the temperature data inside the test area, and because the wells on the south and east sides were producing tar and hot water, it was felt that the water was flowing from the north and west sides. Therefore five more wells, W110, W210, W810, W1010, and W107 were drilled on these sides. The production histories of these wells is given on Table 81. The total production from water wells was estimated at over 20,000 barrels, over twice the amount of water produced with the oil and gas.

CONCLUSIONS AND RECOMMENDATIONS

Many of the results of this test may not be typical of the LINS process, in general. The high water production, overburden leaks, and high heat losses, all tend to make this test somewhat unique. The large amount of water present, while requiring large amounts of heat for its vaporization, also probably aided in recovering hydrocarbons from the deposit, by steam flooding the sand. In addition, many of these results apply only to LINS fields where concentric gas wells are used.

Some of the conclusions from this test are as follows:

1. From 56 to 69%, by weight, of the tar in inside areas of the test pattern, was produced as gas and oil. For a test with concentric gas wells, this is probably the upper limit, because the large amount of water and steam present aided in sweeping the sand free of the tar and oil. About 75% of the recovered hydrocarbons was produced as oil.

2. Recoveries were much higher than those from laboratory retorts, particularly at temperatures below 500°F. This may be due partly to the longer heating time and the flow of oil and gas in the formation, but the high steam flow rates in this test are probably the principal factor.

3. There is gravity segregation in the tar sand deposit, especially in the immediate vicinity of the burners. Therefore, recoveries are higher in the upper portion of the interval being heated.

4. Because of the high temperatures, there is severe coking near the burner, and in the concentric gas casings. At temperatures above 550°F., recoveries are higher in areas removed from the burner wells.

5. Coke is formed at temperatures as low as 500°F.

6. At temperatures above 700°F., there is practically no tar or oil, only coke.

7. The original tar is upgraded considerably, e.g. in this test, 4°API tar was produced as 27°API oil, accompanied by gas having a gross heat of combustion of 990 BTU/scf.

8. The maximum production rates occur at an average formation temperature of about 600°F. Above 700°F., there is very little production.

9. Tar may be produced at gas casing temperatures below 450°F., and coke may be formed in the casings above 600°F. Tar production may be aggravated by high steam rates in the gas casings.

10. The injection of oil and additives into the gas casings has little, if any, effect on the production of tar and emulsions.

11. Coke can be burned off safely in gas casings, by injecting compressed air.

12. Gas casings may become blocked with liquid, but this is not a serious or lasting problem.

13. The emulsions formed in the produced oil can usually be treated by conventional methods.

14. Separate gas wells are not suitable in areas where concentric gas wells are also present, unless they are open to the bottom of the interval. Because of the lower temperatures in separate gas wells, they become blocked with fluids easily.

15. Large amounts of gas and water can be lost through overburden leaks, however, oil losses are less serious.

16. There was no immediate effect on production rates when the burners were shut off, at the end of the test.

17. Extraction in trichloroethylene is a satisfactory test to distinguish between coke and other hydrocarbons, in tar sand samples.

18. Fischer assays of coke yield no oil and very little gas.

19. If all losses are disregarded, the produced gas will supply the energy necessary to heat the tar sand.

20. Although the average heat input was 580 BTU/ft-hr, the average, in a dry formation, may be as low as 230 BTU/ft-hr, depending on losses, casing temperatures, and the final formation temperatures.

21. Normal maintenance and repair causes the burners to be off about 2% of the total heating time.

22. The one-inch burners, in $2\frac{1}{2}$-inch casings, can be operated at heat inputs ranging from 17,000 to 30,000 BTU/burner-hour, over long periods of time, without large changes in the size of the heated interval.

23. Sand losses, which were due mainly to slugging in this test, increased with time and increasing flow rates.

24. Most of the wear on the burner parts was on the top of each part. There was little wear, except where there were projections, such as couplings and centralizers. There was no evidence of serious corrosion.

25. The flat plate centralizers at the cone had the most wear, eroding from the top, at a rate of 1 inch per 2000 hours. These centralizers were made of 18-8 stainless steel.

26. Small amounts of water in the fuel gas can extinguish the flame, either by blocking the orifice, or by blowing out the flame.

27. After the burners reach a temperature of about 1000°F., they will relight themselves, if they go out.

28. The principal safety hazards are hydrogen sulfide poisoning, fuel gas explosions, and burns.

29. If the fuel gas flow rate becomes restricted, the flame may move into the supply tube and cause it to be burned off.

30. The 5% chromium, 1½% silicon, ½% molybdenum alloy burner casings are satisfactory, having shown no signs of erosion or corrosion.

31. It may not be possible to recover casings in thicker formations, because of the tight bond between the tar sand and the casing.

32. There was no casing damage because of movement or expansion of the tar sand.

From the foregoing conclusions, the following recommendations can be made:

1. The use of separate gas wells, in a LINS field, should be investigated, particularly with regard to refluxing and cracking in the casings.

2. Separate gas wells should not be used in the same area with concentric gas wells, unless they are open to the bottom of the formation. This allows liquids to drain to the bottom without blocking the flow of gas.

3. Artificial methods of lifting liquids in separate gas wells should be investigated.

4. The injection of water in the formation, or gas casings, and its effects on recovery, should be investigated.

5. The maximum temperature of the gas casings should be kept between 450 and 600°F. This can be done by placing the bottom of the gas casing at the proper depth, or by manipulating the operating conditions of the burners.

6. The gas casings should be shut in until the maximum temperature in the casings reaches 450°F.

7. The fuel gas should be clean and dry. The Bureau of Mines recommends that the temperature be kept below 150°F.

8. The burner supply tube should be made of flush joint pipe to prevent turbulence and erosion.

even casings!

9. The use of carbon steel, or cheaper alloys, for burner parts should be investigated, particularly for burner tubes.

10. Methods of lighting burners and checking sand levels, without lifting the burners, should be developed.

11. Well spacings larger than 10 feet should be tested.

12. The tar sand formation should be heated no higher than an average temperature of 700°F.

13. An improved method of recovering casings should be developed, either by changing the completion methods, or by treating the surface of the casing to weaken the bond between it and the coked sand.

14. Particular attention should be given to the overburden to ensure a gas-tight seal, it should not be damaged by excessive temperature or pressure.

15. To avoid production losses due to excessive cracking, it may be advisable to shut off some of the burners, after the gas casings reach a temperature of 450°F., and use these wells as production wells. The gas casings would be shut in, in the wells where burners are operating.

This work was carried out by W. J. Shirley, M. O. Eurenius, J. H. Duir, and the authors.

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APPENDIX

STUDIES OF THERMAL DECOMPOSITION OF TAR IN TARSAND.

Summary.

Heating of tarsand in a retort to different temperatures maintained for 2 hours showed that the rate of the decomposition of tar to oil, gas, water and coke is to low below 700°F. Fischer assays run on the residues showed that the coke formed at lower temperatures, decomposes further at higher temperatures yielding gas and water but not a significant amount of oil.

Purpose.

As part of the 100-hole test (L9) it was necessary to analyze partially and completely pyrolyzed tar sand samples. Because the currently used analytical methods had been used mainly on unpyrolyzed tar sand, these tests were performed to investigate the use of these methods on pyrolyzed tar sand. It was also desirable to know if "coke" formed at low temperatures was the same as high-temperature coke, or if it contained a significant amount of oil, either chemically or as a mixture.

The test program included heating of tar sand samples in a Fisher retort for 2 hours at 500, 600, 700, 800, 850°F respectively. The amounts of oil, gas and water, recovered during the heating were to be measured and thereafter determinations of tar content and ignition loss and Fisher assays should be run on each sample.

Equipment and procedure.

The tar sand sample, used for all tests, was obtained through grinding, blending and screening of about 4 lbs of tar sand cores, obtained about a year earlier from the L9 test area. About 2 lbs of the 10 - 30 mesh fraction was used for these tests. It showed the following characteristics:

- water content = 0.23 ± 0.07 % b.w. on wet sample (duplicate determination).

- tar content (through extraction with trichlorethylene) = 12.56 ± 0.06% b.w. on dry sampl .

ignition loss (tar + inorganic CO_2) = 15.64 % b.w. on dry sample.

Fisher assay test (all figures based on dry sample).

oil yield;	8.44 ± 0.02	% b.w.	= 22.25 ± 0.05 gallons/ton (duplicate tests).
gas yield:	0.79 ± 0.01	-"-	= 267 ± 4 st cu ft/ton.
water yield:	0.10 ± 0.05	-"-	= 0.23 ± 0.11 gallons/ton.
residue	90.57 ± 0.02	-"-	- -
loss	0.10 ± 0.04	-"-	
	100.00		

The retort, used for heating, was a standard Fisher assay retort and the products were collected and measured as in the Fisher assay test (see below). The retort was heated at a rate of 14.3°F/ /minute to the predetermined temperature level and kept there for 2 hours. Thereafter the retort was cooled down and weighed and samples for the various analyses were taken.

The Fisher assays were run according to the modified method, described in B.o.M. Report of Investigations 4477, June 1949, with the exception that no glass beads were used in the glass adopter between the retort and the condenser. Further, the condenser and the water bath, in which the liquid collection tube was immersed, were kept at about 70°F instead of 32 ± 9°F. The uncondensable gas was measured over 70°F water and corrected to standard temperature and pressure conditions. In the material balance calculations it was assumed that the specific gravity of the gas was 0.95 (air = 1.00) and that the density of the oil was 0.90 grams/cm^3.

The amount of water produced was determined through distillation of the condensed liquids with white gasoline according to ASTM method D95-40.

Results:

The results are given as a number of material balance tables below. All figures refer to 100 grams of dry, original tar sand sample.

Table 1. Recovered products in the heating tests.

Test No.		2	3	4	5	6
Preheated at °F		500	600	700	800	850
Produced oil	grams	0.00	0.32	1.71	7.50	8.25
gas	"	0.01	0.01	0.23	0.62	0.75
water	"	0.00	0.00	0.00	0.08	0.23
residue	"	99.17	99.61	97.52	91.95	90.69
loss(-) or gain(+)	"	(-) 0.82	(1) 0.06	(-) 0.54	(+) 0.15	(-) 0.08
Total		100.00	100.00	100.00	100.00	100.00

Table 2. Yields from Fisher assays of residues from heating. (Based on 100 gm. of original tar sand)

Oil	grams	8.00	8.11	6.13	0.70	0.00
Gas	"	0.82	0.85	0.77	0.39	0.25
Water	"	0.23	0.13	0.00	0.00	0.04
Fisher coke and sand		90.03	90.51	90.67	91.13	90.49
Loss(-) or gain(+)		(-) 0.09	(-) 0.01	(+) 0.05	(+) 0.27	(+) 0.09
Total		99.17	99.61	97.52	91.95	90.69

Table 3. Overall yields from heating + Fisher assays.

Test No.		2	3	4	5	6
Preheated at	°F	500	600	700	800	850
Oil	grams	8.00	8.43	7.84	8.20	8.25
Gas	"	0.83	0.86	1.00	1.01	1.00
Water	"	0.23	0.13	0.00	0.08	0.27
Fisher coke and sand	"	90.03	90.51	90.67	91.13	90.49
Loss (-) or (+) gain		(-)0.91	(-) 0.07	(-) 0.49	(+) 0.42	(+) 0.01
Total		100.00	100.00	100.00	100.00	100.00

Table 4. Ignition losses and tar contents of residues from heating, compared to Fisher assay products.

Ash content	grams	(no determ.)	86.73	85.93	85.87	86.0[illegible]
Ignition loss (tar + coke + CO_2)	"	-	12.88	11.59	6.08	4.68
Total weight of residue	"	99.17	99.61	97.52	91.95	90.69
Tar content (extr.w.tri)	"	11.40	11.68	8.80	0.64	0.00
Coke + CO_2 (by differ.)	"	-	1.20	2.[illegible]9	5.44	4.68
Fisher assay: oil (see Table 2)	grams	8.00	8.11	6.13	0.70	0.00
gas	"	0.82	0.85	0.77	0.39	0.25
water	"	0.23	0.13	0.00	0.00	0.04
Total volotiles, gram		9.05	9.09	6.90	1.09	0.29

Fig.1 shows the material balance of the tar versus heating temperature.

Conclusions. Within the limits of experimental error it was found that.

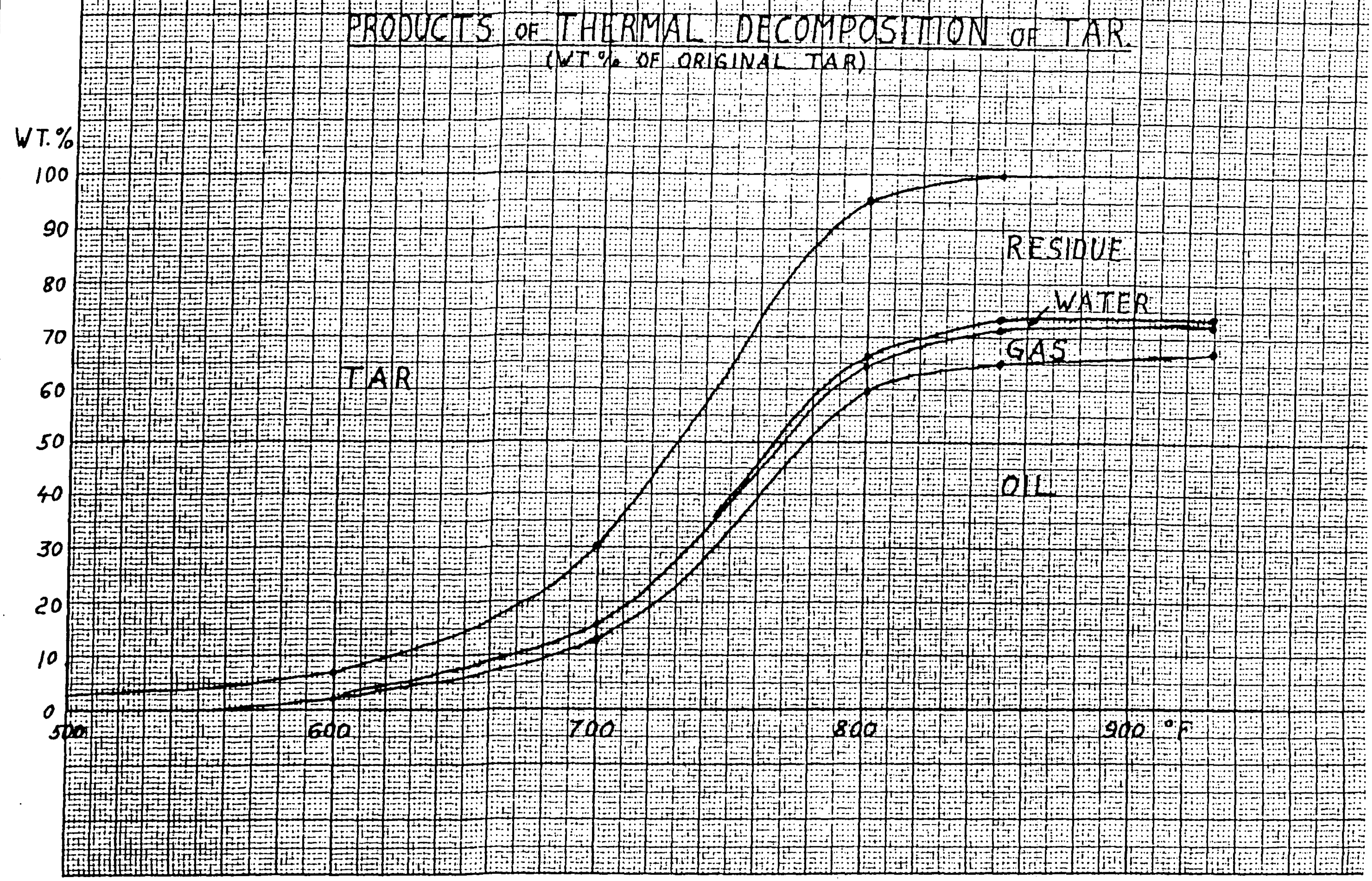
1. The decomposition of tar is slow below 700°F at this conditions. After 2 hours heating at: 600°F 700°F, 800°F, 850°F there remains ~93 %, ~70 % ~5% resp. 0 % of the original tar.

2. The coke residue from the tar decomposition decomposes further at higher temperatures, yielding gas (and water), but no significant amount of oil.

3. Heating of tar sand for 2 hours at temperature levels between 500°F and 850°F before the Fisher assay test does not affect the overall yield of oil considerably. The overall yield of gas appears to increase to some extent after preheating to 700°F or higher.

4. In view of the low yields from unextractable sand, this organic material can be considered to be mostly coke.

Figure 1


PRODUCTS OF THERMAL DECOMPOSITION OF TAR.
(WT % OF ORIGINAL TAR)
WT. %
100
90
80
70
60
50
40
30
20
10
0
500
600
700
800
900 °F
TAR
RESIDUE
WATER
GAS
OIL

HEAT TRANSFER BY CONDUCTION IN A LINS FIELD

During the coring program for L9, it was necessary to calculate the temperatures in the formation, particularly at the locations of the core holes. The following is a brief description of the methods and equations used in these calculations.

If heat is transferred radially from a long thin source, which we assume to be an infinite line source, the following is the solution to the heat conduction equation:

$$T - T_o = \frac{H}{4\pi k} \phi\left(\frac{r^2}{4\alpha\tau}\right) \qquad (1)$$

where:

T = temperature
T_o = initial temperature at $\tau = 0$
H = heat input per unit of time and length
k = thermal conductivity
r = radial distance from source
α = thermal diffusivity
τ = time

$$\phi(\eta) = \int_{\eta}^{\infty} \frac{e^{-x}}{x}\, dx \qquad (2)$$

and

$$\eta = \frac{r^2}{4\alpha\tau}$$

Values of the function, ϕ, have been tabulated by Ingersoll, et al.[1]

In a field where there are a number of line sources, the temperature increment created by any given source can be calculated, using equation (1). The total temperature difference is the sum of these increments:

$$T - T_o = \sum_i \Delta T_i = \frac{1}{4\pi k} \sum_i P_i\, \phi\left(\frac{r_i^2}{4\alpha\tau_i}\right) \qquad (3)$$

where ΔT_i is equal to $T - T_o$ for the i-th source.

---

1. Ingersoll, Zobel, and Ingersoll, "Heat Conduction", McGraw-Hill, New York, 1948, pg. 253-54.

In equation (3), τ_i is the time since the i-th source first began to emit heat. If the heat input of the n-th source was changed, at time τ_a, to a new heat input, Pa, then another term must be added to equation (3), where τ_a is the time since the change was made:

$$T - T_0 = \frac{1}{4\pi k}\left[\sum_i P_i \,\phi\left(\frac{r_i^2}{4\alpha\tau_i}\right) + (P_a - P_n)\,\phi\left(\frac{r_n^2}{4\alpha\tau_a}\right)\right] \qquad (4)$$

If the n-th burner were shut off, then Pa = 0. If all the sources had the same initial heat input, P, then equation (4) becomes:

$$T - T_0 = \frac{P}{4\pi k}\left[\sum_i \phi\left(\frac{r_i^2}{4\alpha\tau_i}\right) + \left(\frac{P_a}{P} - 1\right)\phi\left(\frac{r_n^2}{4\alpha\tau_a}\right)\right] \qquad (5)$$

In this test, the vertical losses were very significant and equation (5) does not apply to the entire interval. However, this equation was used to calculate the maximum temperatures in the wells with the assumption that these temperatures are all affected to the same degree by the vertical losses. By comparing this calculated temperature with the curves measured in the temperature wells, the complete temperature curve, at any point in the test area, could be drawn. The constant, $P/4\pi k$, was evaluated from the temperatures in the nearest temperature wells.

Table 1 .

ORIGINAL TAR ANALYSES IN L9.
(in lb/ft^3)

Well No.	Depth, Feet 0-10	10-15	15-20	20-25	25-30	30-35	35-40	40-45	45-55	15-45
B2-5	4.2(7)	12.8	11.3	10.8	12.5	15.1	16.4	14.4	3.7(5)	13.4
B3-2	6.3(5)	13.7	12.1	11.0	11.9	15.4	16.7	14.1	4.5(4)	13.5
B3-9	7.3(5)	15.6	11.0	11.1	13.4	15.2	15.9	9.5(2)	6.0(4)	12.7(2)
B4-5	6.8(5)	10.6	11.0	11.4	11.9	15.6	16.0	16.1	3.3(4)	13.7
B5-6	6.2(5)	11.2	9.7	9.4	14.7	14.9	16.0	4.5(3½)	-	11.5(3½)
T61	2.5(8)	11.4	8.1	11.9	13.9	16.2	17.2	11.6(1½)	-	13.2(1½)
B6-2	3.6(7)	11.2	10.8	6.6	10.7	13.3	16.6	16.7	5.4(6)	12.5
B6-9	6.7(5)	12.8	11.3	10.8	14.0	16.5	11.8(1)	- (5)	4.3(1)	10.7(6)
B8-5	- (7)	-	6.5	8.7	15.1	13.5	8.5(2)	4.2(1½)	7.3	9.4(3½)
B8-6	4.2(6)	10.5	6.9	8.4	11.9	12.7	15.3	- (5)	7.0	9.2(5)
B9-2	- (10)	-	-	6.9	13.3	14.5	15.0	- (5)	4.5(3)	-
B9-9	- (5)	-	6.7	6.8	10.7	16.1	13.0(1)	- (5)	5.8	8.9(6)

Figures in parenthesis show amount of shale in interval.

Table 2

DESCRIPTION OF L9 BURNER-GAS WELLS.

Hole size:	55 feet deep drilled with a 5 5/8" bit through the top 15 feet and with a 4 3/4" bit through the bottom 40 feet.
Gas casing:	+ $\frac{1}{2}$ feet to 13 feet $4\frac{1}{2}$" sch 10 carbon steel. In B3-5,3-5 and 5-5 13.5 feet of $1\frac{1}{2}$" sch 40 pipe of carbon steel was used, placed along the burner casing.
Burner casing:	+1 feet to 52 feet $2\frac{1}{2}$" sch 40 ASTM A213 55T grade T5B (see analytical description L9-510). The top of the burner casing was sealed off from the top of the gas casing by a $2\frac{1}{2}$" x $3\frac{1}{2}$" tankbushing as shown on Fig. L9-100.
Burner tube:	4 feet of 1" sch 40 25/20 stainless steel. 16 " " 1" sch 40 18/8 " " (After 4440 to 4850 hours 13 feet of 1" 18/8 stainless steel was used).
Cone:	Cast 25/12 stainless steel, 6" long with conical shape of 0.30" inside diameter increasing to 1.32" inside diameter with a thickness of 0.25".
Supply tube:	Counted from cone: 3 feet of 1/4" sch 80 18/8 stainless steel. 7 " " 1/4" sch 40 18/8 " " 19 " " $\frac{1}{2}$" sch 40 carbon steel (After 4440 to 4850 hours 8.5 feet of $\frac{1}{2}$" pipe was replaced by 13.5 feet of 1/[illegible]" sch 40 carbon steel).
Centralizers:	3 1/8" plates 2" long of 18/8 stainless steel were welded symmetrically on supply tube 1 foot above cone and on burner tube 5 and 19 feet below cone. Later the plates above cone and some of the plates at 5 feet below cone were replaced by 6" long 1/8" plates of 18/8 stainless steel.
Wear rings:	Half of a $\frac{1}{2}$" coupling of carbon steel were welded on each side of the 1/4" couplings and on the top of the cone.
Packing:	A burlap packer was set around the gas casing at 12 feet. Five feet of c ment was injected abov this and th r mainder of the hole fill d with sand.

Table 3

DESCRIPTION OF L9 SEPARATE GAS WELLS AND TEMPERATURE WELLS.

Separate gas well, type I.

Hole size: 20 feet deep drilled with 3 3/4" bit.

Casing: 15 feet $1\frac{1}{2}$" sch 40 carbon steel.

Packing: The same as for Burner-Gas well.

Separate gas well, type II.

Same as type I except drilled to 50 feet and filled with gravel from 15'to bottom.

Temperature wells inside the test area.

Hole size: 55 feet deep drilled with 3 3/4" bit.

Casing: 52 feet 2" sch 40 carbon steel.
In T35, T38 and T55 52 feet 1" sch 40 carbon steel was used, placed along the burner casing.

Packing: Filled with sand to 15 feet then with about 5 feet cement and finally sand up to the surface.

Temperature wells T17,T71,T710C,T106.

Hole size: 65 feet deep drilled with 3 3/4" bit.

Casing: 63 2" sch 40 carbon steel.

Packing: The same as for the other temperature wells.

Table 4

DESCRIPTION OF L9 WATER WELLS.

Water wells W22,39,82,99.

Hole size:	55 feet deep drilled with 5 5/8" hole.
Casing:	15 feet 4" sch 10 carbon steel connected to P-line.
Tubing:	50 feet 1½" sch 40 carbon steel.
Pump:	Air driven piston pump with 1/4" rod.
Packing:	The same as for Burner - Gas well.

Water well W56.

Hole size:	75 feet deep drilled with 5 5/8" bit.
Casing:	10 feet 4" sch 40 carbon steel followed by 40 feet 3½" sch 40 carbon steel.
Tubing:	63 feet 1½" sch 40 carbon steel.
Pump:	Air driven piston pump with 1/4" rod.
Packing:	The same as for Burner - Gas well.

Water wells outside the L9 field.

Hole size:	60 feet deep drilled with 5 5/8" bit.
Casing:	15 feet 4" sch 40 carbon steel.
Tubing:	55 feet 1½" sch 40 carbon steel.
Pump:	Air driven piston pump with 1/4" rod.
Packing:	The same as for Burner - Gas well.

Table 5

ANALYSES OF L9 FLUE GAS
OCTOBER 13, 1958.

(Mass spectrometer)

Component	Composition (vol.%) Sample before	Sample after sampling pump
H_2	0.2	0.2
CH_4	0	0
C_2H_6	0.1	0.1
C_3-C_6	0	0
CO	0.3	0.4
CO_2	14.1	13.7
N_2	84.2	84.5
Argon	0.9	0.9
O_2	0.2	0.2
	100.0	100.0

Table 6

CUMULATIVE HEAT INPUT IN L9 FROM START

FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

in Millions BTU.

Row	Number of hrs in oper. for Row	Av.bur.	Burner 1	2	3	4	5	6	7	8	9	10	Total 10^6 BTU for row	Aver.BTU b-hr.
1	7937	7857	207	206	209	210	203	209	209	210	210	210	2083	26,510
2	"	7853	202	207	209	208	208	209	210	208	210	210	2081	26,510
3	"	7902	209	199	199	197	199	199	200	200	200	210	2012	25,450
4	"	7695	210	199	189	176	190	183	198	200	199	210	1954	25,410
5	7490	7248	197	186	181	153	184	186	181	187	187	197	1839	25,400
6	"	7448	197	197	196	196	195	196	197	197	198	198	1967	26,410
7	"	7346	195	197	181	193	188	197	197	197	197	197	1939	26,400
8	"	7260	185	197	183	197	196	167	197	198	197	197	1914	26,330
9	7305	7030	177	193	168	192	191	189	192	171	192	192	1857	26,430
10	"	7233	192	176	192	192	192	192	192	192	192	192	1904	26,350
1-10													19550	26,120

Table 7

METALLURGICAL ANALYSIS OF L9 BURNER CASINGS
GIVEN BY THE BABCOCK & WILCOX COMPANY, BEAVER FALLS, Pa.

Specification:		ASTM A213 55T GRADE T5B
Ultimate strength:		79000 - 82000 psi
Yield point:		53000 - 55600 psi
% Elong in 2":		50 - 53
Hardness:		BHN 148 - 161
Chemical analyses		
wt % of	C	0.10
	Mn	0.42 - 0.44
	S	0.010 - 0.013
	P	0.018
	Si	1.39 - 1.49
	Cr	4.68 - 4.72
	Mo	0.45 - 0.54

Dimension Sch 40 (OD 2. 875", wall 0.203")

Table 8

DESCRIPTION OF BURNER FAILURES.

Burner No.	Date	Hours from start	
B5-5	3.24.1958	655	2 feet of the bottom part of the burner tube burned off, because the flame moved down out of the cone.
B10-2	4.8	1013	Cone and burner casing burned off after $7.7 \cdot 10^6$ BTU had been supplied. There was a lot of water condensing in the top of the burner casing which might have clogged the sand together so it stuck to the casing and thus left too little sand to cover the cone.
B8-9	6.8	2470	Broken supply tube.
B7-2	7.7	3173	Cone burned off.
B8-2	8.16	4135	F-gas burned in ½" supply tube.
B5-1	8.28	4418	-"-
B3-4	9.16	4875	1/4" supply tube 10 feet above cone burned off. A restriction of carbon and metal 3 feet above the cone lowered the gas supply so the gas was ignited in the supply tube.
B9-5	10.27	5854	The supply tube broke off 4 feet above the cone when the sand was checked. The tube had been damaged when a wear ring was welded on earlier.
B5-4	11.13	6280	Burner casing and 1/4" supply tube burned off 10 feet above cone. 2 holes were burned in the casing.

Table 8 (cont)

Burner No.	Date	Hours from start	
B8-7	12.3	6743	A hole in the supply tube 3 feet above cone and just above the wear ring was eroded out by the sand.
B8-6	12.8	6876	Cone and burner casing burned off. Cone burned off 3 inches from its top.
B1-9	12.10	6908	A hole was eroded out by the sand in the supply tube just above the 1/4" coupling, 10 feet above the cone.
B9-3	12.18	7104	1/4" supply tube 10 feet above cone burned off. The burner was stuck and could not be pulled.
B9-8	12.22	7198	1/4" supply tube and burner casing 3 feet above cone burned off.
B7-3	12.29	7389	Burner casing and 1/4" supply tube burned off at 13 feet from ground surface. This was caused by an excessive air injection rate when burning coke out of the gas casing.
B4-9	1.24.1959	8021	Burner casing burned off after the burner had been off 6 hours during a power failure.
B1-1	"	"	Supply tube broke off at 1/4" x ½" reducer because of worn threads.
B2-8	"	"	-"-

Table 9

BURNED OFF BURNER PARTS IN L9.

Hours from start	Part burned off in burner, No.				Reason
	Burner Casing	Cone	Supply tube 1/4"	Supply tube ½"	
1013	B10-2	B10-2			Too little sand
3173		B7-2			
4875			B3-4		Fuel gas ignited in supply tube when gas supply was restricted by rust and oil.
6280	B5-4		B5-4		-"-
6876	B8-6	B8-6			
7104			B9-3		Fuel gas ignited in supply tube when gas supply was restricted by rust and oil.
7198	B9-8		B9-8		-"-
7389	B7-3			B7-3	Too much air was injected in gas casing to burn its coke for unplugging the well.
8021	B4-9				During a shut down

Table 10

BURNER INSPECTIONS.

4.23	1370	Row 2 inspected. Weak spot on B2-7 cone was welded.
6.2	2330	Row 4 inspected. OK
6.26		Row 10 inspected. 3 wear rings 3 ft above cone replaced.
7.8	3190	Row 7 inspected. Replaced several wear rings.
7.9	3215	Row 8 inspected. OK
7.10	3240	Row 9 inspected. OK
8.5	3860	Row 1 inspected. OK
8.6	3890	Row 2 inspected. OK
8.29-9.15	4440- 4850	All rows inspected. All top and most middle centralizers in rows 1 - 4 were worn out. Usually one of the top and one of the middle centralizers in rows 5 - 8 were worn and in rows 9,10 only a few top cent. were damaged. All top centralizers were replaced by 6" plates and damaged middle centralizers by 2" plates.
11.10	6190	B3-3, 5, 7 inspected. Only a worn 1/4" collar in B3-7.
12.11	6940	B1-1 to 8 inspected. The 1/4" couplings 11 feet above the cone were badly damaged by the sand and replaced. Wear rings also installed. 2 wear rings 3 feet above the cone replaced.

Table 10 (cont)

12.12	6960	B1-10 and row 2 inspected. Couplings 10 feet above cone replaced and wear rings installed.
12.13	6990	Rows 6,7,8 and B9-7 to 10 inspected. Replaced 1/4" couplings 10 feet above cone.
12.16	7060	B9-1 to 6 inspected. Replaced 1/4" couplings 10 feet above cone.
12.17	7080	B10-1 to 5 inspected. Replaced 1/4" couplings 10 feet above cone.
12.18	7104	B10-6 to 10 inspected. 1/4" couplings 10 feet above cone replaced.
12.30	7400	Row 3 inspected. 1/4" couplings 10 feet above cone replaced.
12.31	7420	Row 4 inspected. 1/4" couplings 10 feet above cone replaced.
1.2.1959	7470	Row 5 inspected. 1/4" couplings 10 feet above cone replaced.

In many cases where the 1/4" couplings had to be replaced also about 2" of the supply tube above these couplings were badly damaged by the sand and had to be cut off.

Table 11

TOTAL NUMBER OF HOURS L9 BURNERS WERE OFF FROM

START FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

Row	Burner 1	2	3	4	5	6	7	8	9	10	Total Hours	% of total time for cor.row
1	269	275	160	138	385	166	163	147	148	147	1998	2.48
2	395	246	179	192	200	169	153	205	149	147	2035	2.52
3	158	153	168	233	147	167	130	134	128	128	1546	1.92
4	137	139	507	965	587	706	167	124	164	124	3620	4.50
5	84	100	264	1838	170	91	264	76	64	82	3033	4.01
6	72	100	142	122	171	113	80	104	65	63	1032	1.37
7	111	146	729	234	385	91	113	86	77	77	2049	2.71
8	500	82	540	66	145	1270	104	66	67	74	2914	3.86
9	653	88	1031	105	135	194	60	911	58	58	3293	4.47
10	64	665	64	64	60	62	82	64	67	69	1261	1.71
1-10											22781	2.95

Table 12

SUMMARY OF BURNER OFF-TIME IN L9.

	Burner hours	% of total time
Test shut down.		
Power failures	3720	0.49
Maintenance etc. on fuel system	2160	0.28
Instrument failures	2040	0.26
Explosion in fuel lines	400	0.05
Total	8320	1.08
Individual burner off-time.		
Burner failures	6413	0.83
Repair of ground leaks	3842	0.50
Burner maintenance	1825	0.24
Unknown reasons	1572	0.20
Repair of tankbushing leaks	471	0.06
Unplugging of concentric gas wells	338	0.04
Total	14461	1.87
Total	22781	2.95

Table 13

L 9 SHUT - DOWNS.

Date 1958	Hours from start	Off hours	Reason
3.2	118	1	Proportioner failed. Only rows 1-4 on.
	128	3	" " -"-
3.3	140	4	" " -"-
	147	28	" " -"-
3.6	218	3	Power failure -"-
3.7	239	7	Proportioner failed -"-
3.17	477	6	Proportioner adjusted -"-
3.18	499	7	Another propane vaporizer and an empty tank in propane line installed, between vaporizer and F-gas mixing. Only rows 1 to 4 on.
3.25	675	1	Proportioner failed. Only rows 1-8 on
3.26	692	6	Water drains installed in F-lines. Only rows 1-8 on.
4.1	837	7	Capacity of blower checked. Maintenance work on F-station.
4.4	909	3	Power failure.
5.8	1744	6	" "
5.14	1887	4	" "
5.23	2088	2	" "
5.24	2111	2	" "
7.27	3684	4	" "
8.10	3997	7	Propane vaporizer failed.
9.6	4630	1	Circuit braker on compressor op ned.
10.29	5911	6	Power failure.
11.17	6359	4	Explosion in F-lines.
12.10	6922	2	Power failure.
1959			
1.24	8015	6	" "

S u m m a r y:

Rows	1 - 4	off	120	hrs each	= 4800	burner hrs	=1.49%	of tot.time f.rows	1-4
"	5 - 8	"	61	" "	= 2440	" "	=0.81%	" " " " "	5-8
"	9 -10	"	54	" "	= 1080	" "	=0.73%	" " " " "	9-10
"	1 -10				8320	" "	=1.08%	" " " " "	1-10

L9 on 8057 hrs

Rows 1 - 4 on 7937 hrs

" 5 - 8 on 7490 "

" 9 -10 on 7305 "

Table 14

NUMBER OF HOURS L9 BURNERS WERE OFF FOR UNKNOWN REASONS FROM START FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

Row	Burner 1	2	3	4	5	6	7	8	9	10	Total Hours	% of total time for corr. row
1	105	121	33	10	10	2	2	-	-	-	283	0.35
2	28	8	54	62	39	28	8	18	4	2	251	0.31
3	26	10	14	28	14	36	4	2	2	2	138	0.17
4	12	4	-	10	65	8	4	-	4	-	107	0.13
5	2	26	14	8	88	24	10	6	-	18	196	0.26
6	8	36	66	40	90	20	12	-	2	-	274	0.36
7	35	39	4	12	94	19	17	4	-	-	224	0.30
8	2	4	-	-	4	14	2	-	-	-	26	0.03
9	6	4	-	21	2	2	2	-	-	-	37	0.05
10	4	8	4	4	-	-	4	2	4	6	36	0.05
1-10	228	260	189	195	406	153	65	32	16	28	1572	0.20

Table 15

NUMBER OF HOURS L9 BURNERS WERE OFF FOR BURNER FAILURES (BURNED OFF CASINGS, SUPPLY TUBES, CONES AND LIGHTING DIFFICULTIES) FROM START FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

Row	Burner 1	2	3	4	5	6	7	8	9	10	Total Hours	% of total time for corresp. row.
1	36	16					15		2		69	0.09
2								36			36	0.04
3				71							71	0.09
4							28		36[1]		64	0.08
5	18			1765[1]	18						1801	2.38
6					15						15	0.02
7		42	660[1]								702	0.93
8		13				1172[1]	24				1209	1.60
9			947		49			853[1]			1849	2.51
10		597[2]									597	0.81
1-10											6413	0.83

1) Burner casings failures.

2) " " failure. Burner was off 207 hours. New casing was set 1 ft from the original one.

After 1806 hours the burner was off 390 hours because it was stuck in th casing.

Table 16

NUMBER OF HOURS L9 BURNERS WERE OFF TO UNPLUG CONCENTRIC GAS CASINGS FROM START FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

Row	Burner 1	2	3	4	5	6	7	8	9	10	Total Hours	% of total time for cor.row.
1					3	17					20	0.02
2				5	6	15		6			32	0.04
3		11	21			5		5			42	0.05
4		8	20				11				39	0.48
5		10	23			3		6			42	0.06
6			5	18		3		40			66	0.09
7	11			4	14			17	12	12	70	0.09
8							12				12	0.02
9						12					12	0.02
10							3				3	0
1-10											338	0.04

Table 17

NUMBER OF HOURS L9 BURNERS WERE OFF TO REPAIR GROUND LEAKS AND TANKBUSHING LEAKS FROM START FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

Row	Burner 1	2	3	4	5	6	7	8	9	10	Total Hours	% of total time for cor.row
1		11			244[1)]						255	0.32
2	242	117									359	0.45
3											-	-
4			358	829	342	570					2099	2.60
5							190				190	0.25
6											-	-
7				152[1)]	212						364	0.48
8	433				75[1)]						508	0.67
9	416[1)]					122					538	0.71
10											-	-
1-10											4313	0.56

[1)] Tankbushing leaks.

Table 18

NUMBER OF HOURS L9 BURNERS WERE OFF FOR MAINTENANCE WORK ON BURNERS (INSPECTING BURNERS, REPLACING COUPLINGS AND WEAR RINGS, CHANGING BURNER POSITION, CLEANING ORIFICE PLATES, BURNED OFF HOSES, MISC. WORK ON F- LINE) FROM START FEBRUARY 25, 1958 TO SHUT OFF JANUARY 26, 1959.

Row	Burner 1	2	3	4	5	6	7	8	9	10	Total Hours	% of total time for cor row
1	8	7	7	8	8	27	26	27	26	27	171	0.21
2	5	1	5	5	35	6	25	25	25	25	157	0.20
3	12	12	13	14	13	6	6	7	6	6	95	0.12
4	5	7	9	6	60	8	4	4	4	4	111	0.14
5	3	3	166 1)	4	3	3	3	3	3	3	194	0.26
6	3	3	10	3	5	29	7	3	2	2	67	0.09
7	4	4	4	5	4	11	35	4	4	4	79	0.10
8	4	4	479 2)	5	5	23	5	5	6	13	549	0.73
9	177 3)	30	30	30	30	4	4	4	4	4	317	0.43
10	6	6	6	6	6	8	21	8	9	9	85	0.12
1-10											1825	0.24

1) Burner was shut off for 163 hours from 5450 hours from start to test its concentric gas well as a separate gaswell. For 73 hours from 5613 hours from start the burner was run at a heat input of 12,000 BTU/h.

2) Burner was shut off for 170 hours and 217 hours from 5690 and 6093 hours from start, resp. For 227 hours after 5860 hours from start the burner was run at a heat input of 12,000 BTU/h. The purpose was to test its conc. gas well as a sep. gas well.

3) The burner was shut off for 146 hours from 1053 hours from start when a new hole was drilled for B10-2.

Table 19

TEMPERATURE OF EXHAUST GAS IN L9 MEASURED INSIDE THE BURNER CASINGS AT GROUND LEVEL.

5600 hours from start. October 15 - 16, 1958.

Row No.	Burner, No. 1	2	3	4	5	6	7	8	9	10	Averag
1	240	250	360	340	270	298	330	430	380	260	316
2	324	420	330	286	284	300	324	432	446	242	339
3	300	264	220	320	312	310	346	332	264	414	308
4	316	288	280	344	294	300	330	300	370	275	310
5	425	325		345	320	290	270	320	480	315	343
6	304	310	290	380	520	480	524	330	302	278	372
7	284	300	490	382	326	484	530	344	320	288	375
8	294	342	284	390	364	348	366	390	254	252	328
9	258	276	305	245	274	280	218	310	236	242	264
10	204	274	274	308	232	262	278	256	260	250	260
										Average	322

6300 hours from start. November 13 - 16, 1958.

Row No.	Burner, No. 1	2	3	4	5	6	7	8	9	10	Average
1	250	280	330	250	318	334	305	415	360	250	309
2	304	460	358	350	280	186	315	380	365	310	331
3	285	160	310	310	290	295	285	280	280	362	286
4	276	328	285	328	295	300	275	250	305	235	288
5	290	305	290	240	295	280	420	475	405	370	337
6	380	310	380	320	475	540	530	300	356	300	389
7	162	295	325	295	295	372	320	330	350	260	300
8	250	246	230	272	210	325	305	278	280	190	259
9	240	290	225	300	335	275	270	370	280	258	284
10	205	275	280	290	268	250	255	265	238	250	258
										Average	304

Table 20

HEAT BALANCE FOR TEST L9

	Millions of Btu	%
Total Heat Input	19,550	100
Heat Content of Exhaust Gas (300°F)	2,560	13
Sensible Heat of Produced Fluids (300°F)		
Oil	120	
Gas	30	
Water	3,150	
	3,300	17
Heat Through Casing to Overburden (205 Btu/ft-hr from 0 to 14 ft)	2,160	11
Heat Content of Formation* (from 14 to 42 ft, 460 Btu/ft-hr)	2,560	13
Vertical Heat Losses from Heated Formation*	1,040	5
Side Heat Losses from Heated Formation*	2,760	15
Heat Through Casing to Internal Below 42 ft	2,620	13
Losses Which are not Accounted For	2,550	13
TOTAL	19,550	100

*The heated formation includes only the volume inside the second row of wells from the edge, between depth of 14 and 42 feet.

Table 21

TOTAL L9 PRODUCTION DATA.

Oil, bbls	2,665	
tons	415	
Gas, 10^3 S cu ft	4,520	
tons	112	
Water, bbls	9,232	
tons	1,615	
Gas/Oil ratio, S cu ft/bbl	1,700	
lb/lb		0.27
Water/Oil ratio bbl/bbl		3.46
lb/lb		3.89

Gross heat of combustion, gross 10^6 BTU

Oil	15,880
Gas	4,470
Oil + Gas	20,350
Input	19,550
	800

Table 22

COMPOSITE ANALYSIS OF L9 PRODUCED GAS.

Component	Composition, vol % 1)	
H_2	39.6	
H_2S	9.2	12.2
CO_2	2.3	
N_2+CO	0.7	
CH_4	28.6	42.9
C_2H_6	6.7	
C_3H_8	3.9	
iC_4H_{10}	1.2	
nC_4H_{10}	1.3	
iC_5H_{12}	0.3	
nC_5H_{12}	0.9	
C_2H_4	0.9	4.4
C_3H_6	0.6	
C_4H_8	1.7	
C_5H_{10}	1.2	
C_3H_4	0.1	0.2
C_4H_6	0.1	
Av.C_6	0.7	
	100.0	
Heat of Combustion 2)	990 Btu/scf Gross	
	910 Btu/scf Net	
Spec.gravity 2)		
Air = 1.0	0.650	
kg/m^3 at 32°F	0.840	
lbs/S cu ft	0.0496	
True spec.heat 2)		
BTU/S cu ft,°F at 65°F	0.0242	
" " 300°F	0.0286	

1) Calculated from Diagrams L9-508-1 through 5.

2) Calculated from the above gas analyses.

Table 23

ANALYSES OF L9 PRODUCED GAS.

(Mass. Spectrometer)

July 26, 1958.

Component	Composition (vol.%) Row 1		Rows 7 and 8		Row 10		Total L9	
H_2	38.0		40.3		40.1		38.2	
H_2S	13.4		12.5		7.8		13.6	
CO_2	5.5	20.1	4.2	18.0	10.5	20.9	4.7	19.9
N_2+CO	1.2		1.3		2.6		1.6	
CH_4	24.4		24.9		26.5		23.0	
C_2H_6	6.4		6.3		5.8		6.4	
C_3H_8	3.8		3.5		2.6		3.7	
iC_4H_{10}	0.8	37.3	0.8	37.2	0.3	36.2	1.1	36.5
C_4H_{10}	1.2		1.0		0.7		1.3	
iC_5H_{12}	0.1		0.3		0.1		0.1	
nC_5H_{12}	0.6		0.4		0.2		0.9	
C_2H_4	1.0		1.0		0.6		0.9	
C_3H_6	1.3	4.1	1.2	4.2	0.9	2.6	0.9	4.6
C_4H_8	1.2		1.4		0.8		1.7	
C_5H_{10}	0.6		0.6		0.3		1.1	
C_3H_4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
C_4H_6	0.0		0.0		0.0		0.1	
Av.C_6	0.4		0.2		0.1		0.6	
	100.0		100.0		100.0		100.0	
Heat of comb.gross BTU/ft^3	888.0		873.1		735.8		934.7	
Spec.grav. Air= 1.0	0.679		0.641		0.627		0.701	

ANALYSES OF L9 PRODUCED GAS.
(Mass.Spectrometer)

Component	Composition (vol.%) August 9 Row 1		Rows 7 and 8		Row 10		Total L9		August 23 Total L9	
H_2	36.0		39.0		45.7		35.2		35.6	
H_2S	13.3		12.2		8.1		13.0		12.2	
CO_2	3.9	18.1	3.2	16.0	7.5	17.4	4.0	17.3	2.8	15.7
N_2+CO	0.9		0.6		1.8		0.3		0.7	
CH_4	26.3		25.7		26.1		25.9		26.0	
C_2H_6	7.3		7.0		4.7		7.3		7.5	
C_3H_8	4.3		4.1		2.1		4.5		4.8	
iC_4H_{10}	1.1	41.0	0.9	39.7	0.3	34.0	1.2	41.5	1.4	42.3
nC_4H_{10}	1.3		1.2		0.5		1.4		1.4	
iC_5H_{12}	0.1		0.3		0.0		0.4		0.4	
nC_5H_{12}	0.6		0.5		0.3		0.8		0.8	
C_2H_4	1.1		1.0		0.7		1.0		1.5	
C_3H_6	1.4		1.6		0.9		1.3		1.3	
C_4H_8	1.3	4.5	1.7	5.0	0.8	2.7	2.0	5.3	1.9	5.7
C [illegible]0	0.7		0.7		0.3		1.0		1.0	
C_3 [illegible] 4	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2
C_4H_6	0.0		0.0		0.0		0.1		0.1	
Av.C_6	0.4		0.3		0.2		0.5		0.5	
	100.0		100.0		100.0		100.0		100.0	
Heat of comb.gross BTU/ft^3	963		953		723		1013		1033	
Spec.grav. Air=1.0	0.690		0.660		0.455		0.724		0.714	

The samples did not contain any C_2H_2, C_4H_2, C_4H_4, Benzene or NH_3.

Table 25

ANALYSES OF L9 PRODUCED GAS.

Composition (vol. %)

Component	Sept.5		Sept. 19.	
H_2	34.4		36.9	
H_2S	12.4		13.5	
CO_2	2.5	15.3	2.3	16.6
N_2+CO	0.4		0.8	
CH_4	25.6		24.2	
C_2H_6	7.6		7.2	
C_3H_8	4.6		4.4	
iC_4H_{10}	1.4	42.0	1.5	40.2
nC_4H_{10}	1.5		1.6	
iC_5H_{12}	0.2		0.1	
nC_5H_{12}	1.1		1.2	
C_2H_4	1.7		0.9	
C_3H_6	1.4	7.1	0.5	5.1
C_4H_8	2.5		2.1	
C_5H_{10}	1.5		1.6	
C_3H_4	0.2	0.3	0.2	0.2
C_4H_6	0.1		0	
AvC_6	0.8		1.0	
Benzene	0.1		0	
Heat of Combustion Gross BTU/S,cuft	1096		1055	
Spec.gravity Air = 1.0	0.745		0.729	

Table 26

ANALYSES OF L9 PRODUCED GAS
(MASS SPECTROMETER)

Component	Composition vol. %			
	October 3		October 17	
H_2	37.6		37.5	
H_2S	13.2	15.9	11.2	13.7
CO_2	2.0		1.9	
N_2+CO	0.7		0.6	
CH_4	24.8	41.6	26.2	42.9
C_2H_6	7.2		7.7	
C_3H_8	4.9		4.4	
i C_4H_{10}	1.7		1.5	
n C_4H_{10}	1.6		1.7	
i C_5H_{12}	0.4		0.2	
n C_5H_{12}	1.0		1.2	
C_2H_4	0.8	4.1	0.9	4.8
C_3H_6	0.3		0.4	
C_4H_8	1.8		2.0	
C_5H_{10}	1.2		1.5	
C_3H_4	0.1	0.1	0.2	0.2
C_4H_6	0		0	
Av.C_6	0.7		0.9	
Heat of comb.gas BTU/S cu.ft	1035		1062	
Spec.grav. Air=1.0	0.706		0.703	

Table 27

ANALYSES OF L9 PRODUCED GAS.

(Mass Spectrometer)

Component	Composition vol.% Nov. 19x)		Nov. 28	
H_2	36.2		40.0	
H_2S	6.7	45.3	7.0	49.2
CO_2	1.5	9.1	2.1	9.2
N_2+CO	0.9		0.1	
CH_4	26.8		31.8	
C_2H_6	6.7		6.7	
C_3H_8	3.0		3.6	
i C_4H_{10}	-	44.7	1.1	45.3
nC_4H_{10}	2.1		1.2	
iC_5H_{12}	-		0.1	
nC_5H_{12}	6.1		0.8	
C_2H_4	0.2		1.0	
C_3H_6	4.7		0.6	
C_4H_8	-	5.7	1.6	4.5
C_5H_{10}	0.8		1.3	
C_2H_2	0.2		-	
C_3H_4	-	0.6	0.1	0.2
C_4H_6	0.2		0.1	
C_4H_2	0.2		-	
C_6+	3.5		0.8	
Benzene	0.2		-	
Heat of comb.gas, BTU/S cu ft	1283		996	
Spec.grav. Air = 1.0	0.806		0.623	

x) May be errors in olefin, C_3 and C_{4+} portions of analysing.

L9-502-6.
1.1.59.BP.

Table 28

ANALYSES OF L9 PRODUCED GAS
(Mass Spectrometer)

Component	Dec. 12		Dec.29	
	Composition, vol.%			
H_2	42.1		44.0	
H_2S	7.1	9.0	5.9	
CO_2	1.3		2.2	8.1
$CO+N_2$	0.6		0	
CH_4	31.6		32.8	
C_2H_6	6.5		5.7	
C_3H_8	3.4	44.4	2.9	43.9
iC_4H_{10}	0.8		0.8	
nC_4H_{10}	1.2		1.0	
iC_5H_{12}	0.1		0.1	
nC_5H_{12}	0.8		0.6	
C_2H_4	0.8		0.8	
C_3H_6	0.7	3.7	0.6	3.4
C_4H_8	1.3		1.2	
C_5H_{10}	0.9		0.8	
C_3H_4	0.1	0.2	0.1	0.1
C_4H_6	0.1		0	
Av.C_6	0.6		0.5	
			100.0	
Heat of Combustion Gross BTU/S cu ft	945		895	
Spec.gravity Air = 1.0	0.583		0.549	

L9-503-1.
July 26, 1958.

Table 31

ANALYSES OF L9 PRODUCED LIQUIDS.

3620 hours from start.

	Row 1	Rows 7 & 8	Row 10	Total L9
Liquid Product				
Gravity, °API	27.5	23.7	21.4	25.8
Sulfur, wt.%	2.24	2.49	2.20	2.38
Nitrogen, wt.%	0.440	0.367	0.309	0.378
Distillation, D-1160T, Mod., °F				
IBP	118	136	223	101
5 vol % O.H	250	260	355	270
10	320	345	425	320
20	415	450	500	400
30	465	515	550	470
40	500	565	585	520
50	540	605	630	570
60	590	650	680	615
70	645	705	750	670
80	720	775	835	740
90	815	855	930	840
95	900	920	-	-
Max.:	915	970	965	910
Vol.Rec.	95.5	96.0	92.0	94.0

Table 30

ANALYSES OF L9 PRODUCED GAS.
(Mass Spectrometer)
February 6, 1959

Component	Composition, vol.%	
H_2	49.1	
H_2S	7.6	13.8
CO_2	3.7	
$CO+N_2$	2.5	
CH_4	28.5	35.2
C_2H_6	3.7	
C_3H_8	1.6	
iC_4H_{10}	0.5	
nC_4H_{10}	0.5	
iC_5H_{12}	0.1	
nC_5H_{12}	0.3	
C_2H_4	0.2	1.4
C_3H_6	0.0	
C_4H_8	0.7	
C_5H_{10}	0.5	
C_3H_4	0.2	0.2
C_4H_6	0.0	
Av. C_6	0.3	
	100.0	
Heat of Combustion Gross BTU/S cu ft	723	
Spec.gravity Air = 1.0	0.495	

Table 29

ANALYSES OF L9 PRODUCED GAS.

(Mass Sp ctrometer)

Component	January 9		January 23		January 23 Sweet gas	
			Composition, vol. %.			
H_2	43.2		44.5		43.2	
H_2S	6.0		5.7		0	
CO_2	2.9	9.2	3.1	8.9	3.5	7.4
$CO+N_2$	0.3		0.1		3.9	
CH_4	34.6		33.8		33.3	
C_2H_6	5.1		5.0		4.8	
C_3H_8	2.5		2.4		2.6	
iC_4H_{10}	0.7	44.6	0.6	43.1	0.8	43.7
nC_4H_{10}	0.7		0.8		1.0	
iC_5H_{12}	0.9		0.1		0	
nC_5H_{12}	0.1		0.4		1.2	
C_2H_4	0.6		0.7		1.0	
C_3H_6	0.6		0.6		0.6	
C_4H_8	1.2	3.0	1.0	3.0	1.5	4.4
C_5H_{10}	0.6		0.7		1.3	
C_3H_4	0		0.1		0.2	
C_4H_6	0		0	0.1	0.1	0.3
Av. C_6	0		0.4		1.0	
	100.0		100.0		100.0	
Heat of Combustion Gross BTU/Scuft	853		843		922	
Spec.grav. Air = 1.0	0.536		0.528		0.578	

Table 32

ANALYSES OF L9 OIL.

6410 hours from start.

Sample taken from treater November 19, 1958.

Gravity, °API 27.9

Distillation, D-1160T, Mod., °F

IBP	149
5 vol %	240
10	290
20	385
30	460
40	515
50	560
60	600
70	635
80	680
90	735
Max.	755
Vol.Rec.	93.5

Sulphur, % by weight 2.55

Nitrogen, % by weight 0.423

6-29-59

TABLE 33

ANALYSIS AND CALCULATED PROPERTIES OF COMPOSITE OIL SAMPLE

Gravity	27.8°API	
Sulfur	2.15%	
Nitrogen	0.38%	
Carbon Res.	0.11%	
Distillation, D-1160T Mod.		
IBP	122°F	50.0 °C
5% (Vol.)	262	128
10%	295	146
20%	367	186
30%	445	229
40%	515	268
50%	570	299
60%	610	321
70%	640	338
80%	680	360
90%	735	391
95%	765	407
Max.	865	463
Vol. Rec.	98.5%	

Gross Heat of Combustion[1] : 5.96×10^6 BTU/bbl.

True Specific Heat of liquid[1] (60°F.) : 0.43 BTU/lb - °F.
(300°F.) : 0.56 BTU/lb - °F.

True Specific Heat of Vapor[1] (60°F.) : 0.35 BTU/lb - °F.
(300°F.) : 0.45 BTU/lb - °F.

Heat of Vaporization[1] (1 atm.) : 110 BTU/lb.

1. Calculated from: W. L. Nelson, "Petroleum Refinery Engineering".

Table 34

POST - HEATING CORE DATA

FISCHER ASSAYS OF EXTRACTED, COKED SAND.

Well	Depth	Max.temp.	Coke (lb/ft^3)	Oil (wt %)	Water (wt.%)	Residue (wt %)	Gas + Loss (wt %)
C9	20-25	630-680	3.9	0	0.05	99.10	0.85
C11	30-35	680-700	3.3	0	0.05	99.75	0.20
C13	25-30	680-700	3.4	0	0.05	99.75	0.20
C13	30-35	640-690	5.2	0	0.10	99.55	0.35
C13	35-40	570-640	7.1	0	0.50	99.35	0.15
C14	15-20	580-660	2.3	0	0.05	99.54	0.41
C14	30-35	510-580	1.3	0	0.15	99.54	0.31

Table 35

L9 POST-HEATING CORE ANALYSES - CORE HOLE C1.

Depth ft	Recovery %	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0- 5	95	Soil	(115)	.06	-	-0.1	-
5-10	90	TS	117.1	14.95	12.2	-2.8	-23
10-15	100	"	128.8	13.82	13.0	-0.8	- 6
15-20	100	"	141.4	11.75	8.0	-3.8	-48
20-25	100	"	145.5	8.45	10.5	2.1	20
25-30	95	"	124.9	11.40	12.9	1.5	12
30-35	100	"	123.3	17.77	17.0	-0.8	- 5
35-40	100	Shale 36-41	102.4	1.47	2.8	1.3	46
40-45	100	Shale & TS	146.8	4.08	4.5	0.4	9
45-50	50	"	105.9	5.79	6.0	0.2	3
50-55	95	TS	110.3	5.16	6.0	0.8	13
55-60	85	"	107.5	4.28	6.0	1.7	28
60-65	85	"	112.4	6.47	6.0	-0.5	- 8
Avg.				8.1	8.1	0.0	0

Cok - none. Total H-C - same as "Tar".

Table 36

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C2.

Depth ft	Recovery %	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	60	Soil	(120)	0.48	-	- 0.5	-
7-10	95	TS	122.8	16.97	13.0	- 4.0	-31
10-15	100	"	117.2	15.06	14.0	- 1.1	- 8
15-20	"	"	133.9	12.57	8.5	- 4.1	-48
20-25	"	"	128.3	10.93	11.0	0.1	1
25-30	"	"	125.5	11.33	13.0	1.7	13
30-35	"	"	112.4	15.14	17.0	1.9	11
35-39	"	(lost.circ.)	122.6	16.23	14.5	-1.7	-12
39-45	50	Shale	-	0	-	-	-
45-50	30	TS	113.7	5.88	3.5	-2.4	-69
50-55	100	"	113.8	4.39	5.0	0.6	12
Avg.				9.01	8.3	-0.7	-8

Coke: None.   Total H-C: Same as "Tar".

Table 37

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C3.

Depth ft	Recovery %	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	(115)	(0.77)	-	-0.8	-
5-10	"	TS	128.2	15.78	13.5	-2.3	-17
10-15	"	"	129.3	14.02	14.0	0.0	0
15-20	"	"	132.2	10.63	8.6	-2.0	-23
20-23	"	"	127.8	12.79	11.2	-1.6	-14
23-28	70	(lost circ.)	129.5	11.37	12.0	0.6	5
28-31½	90	TS	124.5	17.93	15.0	-2.9	-19
31½-33½	"		(125)	(19.45)	17.5	-2.0	-11
33½-40	100	Shale	-	0	-	-	-
40-45	"	TS	129.2	6.55	3.0	-3.6	-120
45-50	"	"	115.0	5.52	4.5	-1.0	-22
50-55	"	"	110.[illegible]	4.40	7.0	2.6	37
Avg.				8.82	7.9	-0.9	-11

Coke: Non Total H-C: Same as "Tar".

Table 38

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C4.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	(115)	0.78	-	-0.8	-
5-10	20	TS	(130)	13.77	14.6	0.8	5
10-15	95	"	130.4	15.64	17.0	1.4	8
15-20	100	"	139.1	12.16	10.6	-1.6	-15
20-25	"	"	131;2	10.18	12.0	1.8	15
25-30	"	"	124.0	10.45	13.0	2.6	20
30-35	"	"	115.9	11.71	16.5	4.8	29
35-37	"	"	119.3	16.7	15.0	-1.7	-11
37-37½	"	Coarse TS	(118.2)	9.5	15.0	5.5	37
37½-42½	"	TS	118.2	15.85	15.6	-0.3	- 2
42½-47½	"	Shale	-	-	-	-	-
47½-50	"	TS	(115)	10.0	8.0	-2.0	-25
50-55	80	"	(115)	9.69	3.0	-6.7	-223
Av.				10.26	10.3	0.0	0

Coke: Non Total H-C: Same as "Tar".

Table 39

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C5.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-10	100	Soil	-	-	-	-	-
10-15	"	TS	138.0	8.43	11.5	3.1	27
15-20	"	"	143.3	6.76	10.5	3.7	35
20-25	"	"	148.6	6.67	6.0	-0.7	-12
25-30	60	(lost circ.)	104.7	8.49	12.3	3.8	31
30-35	100	TS	122.4	15.14	15.2	0.1	1
35-40½	"	"	117.3	15.31	16.5	1.2	7
40½-48	95	Shale	-	-	-		-
[illegible]-55	100	TS	114.7	7.89	5.7	-2.2	-39
Avg.				6.67	7.4	0.7	9

Coke: None. Total H-C: Same as "Tar".

Table 40

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C6.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7½	100	Soil	-	-	-	-	-
7½-10	"	TS	(130)	12.52	12.0	-0.5	-4
10-15	"	"	133.2	11.95	12.0	0.1	1
15-20	"	"	124.9	10.74	11.5	0.8	7
20-25	"	"	133.0	7.26	6.0	-1.3	-22
25-30	65	"	128.9	10.25	10.0	-0.3	- 3
30-35	70	"	116.9	11.51	16.0	4.5	28
35-40	95	"	120.2	16.55	16.5	-0.1	- 1
40-46	100	"	119.1	14.78	17.0	2.3	14
46-52½	"	Shale	-	-	-	-	-
52½-56½	"	TS	114.9	6.50	7.5	1.0	13
				8.62	9.5	0.9	9

Coke: None Total H-C: Same as "Tar".

Table 41

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C7.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil		-	-	-	-
7-12	70	TS	96.5	9.67	11.8	2.1	18
12-18	100	"	127.6	13.40	14.2	0.8	6
18-20	60	"	(130)	9.40	12.2	2.8	23
20-25	65	"	131.8	4.02	10.0	6.0	60
25-30	85	"	(110.3)	7.49	11.8	4.3	36
30-35	90	"	(110.7)	12.85	16.0	3.2	20
35-40	100	"	128.9	20.37	17.0	-3.4	-20
40-45	"	"	122.0	13.42	14.0	0.6	4
45-47	"	"	124.7	9.96	12.0	2.0	17
47-51	"	Shale	-	-	-	-	-
51-55	80	TS	143.7	5.26	3.5	-1.8	-51
Avg.				8.71	10.0	1.3	13
Avg (15-45)				11.6	13.7	2.1	15

Coke: Non . Total H-C: Same as "Tar".

Table 42

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C8.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	(115)	0.71	-	0.7	-	-0.7	-
7-10	90	TS	117.4	7.23	-	7.2	12.6	5.4	43
10-15	50	"	124.5	5.50	-	5.5	14.0	8.5	61
15-20	70	TS & Coke	130.3	2.97	0.7	3.7	12.3	8.6	70
20-25	30	"	(115)	1.13	1.8	2.9	10.2	7.3	72
25-30	30	"	114.9	5.10	1.3	6.4	11.9	5.5	46
30-35	50	"	121.1	1.25	4.2	5.4	15.6	10.2	65
35-40	90	"	119.7	7.26	-	7.3	16.8	9.5	57
40-45½	95	"	130.6	8.76	-	8.8	14.1	5.3	38
45½-50	100	Shale		-	-	-	-	-	-
50-55	"	TS	153.2	3.42	-	3.4	4.3	0.9	21
Avg.				3.78 (39%)	0.7 (7%)	4.5	9.8	5.3	54
Avg. (15-45(				4.4 (33%)	1.4 (10%)	5.8	13.5	7.7	57

Table 43

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C9.

D pth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft	Loss %
0-6½	100	Soil	112.4	0.75	-	0.8	-	-0.8	-
6½-11½	"	TS	(120)	4.50	-	4.5	12.9	8.4	65
11½-14	"	"	(120)	3.04	-	3.0	13.7	10.7	78
14-20	"	TS & Coke	122.8	1.63	2.0	3.6	12.4	8.8	71
20-25	"	"	131.9	0	3.9	3.9	11.0	7.1	65
25-30	"	"	112.0	0	4.8	4.8	11.9	7.1	60
30-35	"	"	125.2	0	6.8	6.8	15.4	8.6	55
35-40	"	"	125.0	0	9.7	9.7	16.7	7.0	42
40-46½	"	"	116.6	7.92	0.9	8.8	14.1	5.3	38
46½-51½	"	Shale	-	0	-	-	-	-	-
51½-55	"	TS	152.1	3.27	-	3.3	4.3	1.0	23
Avg.				1.96	2.6	4.6	10.1	5.5	54
				(19%)	(26%)				
Avg.(15-45)				1.59	4.7	6.3	13.6	7.3	54
				(12%)	(35%)				

Table 44

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C1Q.

D pth	Recovery	Description	Density	Extr. Tar	Original Tar	Loss	
ft			lb/ft^3	lb/ft^3	lb/ft^3	lb/ft^3	%
0-7	100	Soil	(115)	0.30	-	-0.3	
7-10	65	TS	122.5	11.18	11.7	0.5	4
10-15	95	"	127.7	11.34	14.5	3.2	22
15-16½	95	"	118.0	9.65	12.7	3.1	24
16½-17½	80	"	127.8	4.64	12.0	7.4	62
17½-20	100	"	128.2	4.28	11.3	7.0	62
20-25	100	"	119.5	3.44	10.0	6.6	66
25-30	"	"	118.9	3.83	12.5	8.7	70
30-35	"	"	112.0	7.46	15.5	8.0	52
35-40	"	"	119.3	11.12	16.5	5.4	33
40-45½	"	"	119.3	10.31	14.5	4.2	29
45½-51	"	Shale	-	0	-	-	-
51-55	"	TS	140.2	4.68	4.7	0.0	0
Avg.				5.94	9.8	3.9	40
Avg (15-45½)				7.07	13.5	6.4	47

Table 45

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C[illegible].

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-8	100	Soil	(115)	.37	-	0.4	[illegible]	-0.4	-
8-10	"	TS	107.9	8.71	-	8.7	13.5	4.8	36
10-20	5	coarse TS	(110)	6.27	-	6.3	13.0	6.7	52
20-25	85	TS & Coke	123.7	0.49	1.2	1.7	10.0	8.3	83
25-30	20	"	111.5	0.39	3.8	4.2	12.5	8.3	66
30-35	75	"	106.9	0.34	3.3	3.6	15.1	11.5	76
35-40	95	"	104.3	4.95	0.6	5.5	16.5	11.0	67
40-45	100	"	114.9	8.03	1.5	9.5	14.5	5.0	34
45-46½	"	"	(115)	8.95	-	9.0	12.6	3.6	29
46½-52	"	Shale	-	-	-	-	-	-	-
52-55	"	TS	119.5	2.77	-	2.8	4.5	1.7	38
Avg.				3.20 (33%)	0.9 (9%)	4.1	9.7	5.6	58
Avg. (15-45)				3.08 (23%)	1.7 (13%)	4.8	13.6	10.5	77

Table 46

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C12.

Depth	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	(120)	.32	-	0.3	-	-0.3	-
7-10	70	TS	111.1	9.48	-	9.5	13.9	4.4	32
10-15	85	"	120.8	7.05	-	7.1	13.2	6.1	46
15-20	95	"	129.6	2.79	1.8	(4.6)	11.5	6.9	60
20-25	95	"	129.8	.21	3.1	3.3	10.8	7.5	69
25-30	35	"	112.6	-	2.8	2.8	12.5	9.7	78
30-35	100	"	119.9	.06	6.9	7.0	15.1	8.1	54
35-40	"	"	(120)	.12	13.8	13.9	16.5	2.6	16
40-46	"	"	118.6	6.23	0.1	6.3	14.5	8.2	57
46-52½	"	Shale	-	-	-	-	-	-	-
52½-55	"	TS	151.9	2.95	-	3.0	4.4	1.4	32
Avg.				2.30	2.6	4.9	9.8	4.9	50
				(23%)	(27%)				
Avg (15-45)				1.57	4.7	6.3	13.5	7.2	53
				(12%)	(35%)				

Table 47

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C13.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	(120)	.34	-	0.3	-	-0.3	-
5-10	"	TS	111.0	9.10	-	9.1	12.0	2.9	24
10-15	80	" & coke	114.7	6.69	-	6.7	12.8	6.1	48
15-20	60	"	121.6	.49	2.0	2.5	7.9	5.4	68
20-25	95	"	128.2	.06	3.5	3.6	10.3	6.7	65
25-30	95	"	114.3	.06	3.4	3.5	13.1	9.6	73
30-35	100	"	121.4	1.85	5.2	7.0	16.5	9.5	58
35-40	80	"	122.5	2.44	7.1	9.5	14.0	4.5	32
40-44	70	"	124.1	15.26	-	15.3	14.0	-1.3	- 9
44-45	100	Shale	-	-	-	-	-	-	-
45-47	"	TS	141.5	9.08	-	9.1	5.3	- 3.8	-72
47-53	"	Shale	-	-	-	-	-	-	-
Avg.				3.48	2.0	5.5	9.4	3.9	41
				(37%)	(21%)				
Avg. (15-45)				2.85	3.6	6.4	12.2	5.8	48
				(23%)	(30%)				

Table 48

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C14.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-6½	100	Soil	(120)	1.44	-	1.4	-	-1.4	-
6½-10	90	TS & coke	116.2	4.92	-	4.9	12.0	7.1	59
10-15	30	"	117.1	5.88	-	5.9	12.5	6.6	53
15-20	95	"	123.3	1.80	2.3	4.1	7.9	3.8	48
20-25	100	"	128.6	0	2.7	2.7	10.1	7.4	73
25-30	30x)	"	110.5	.06	1.6	1.7	13.2	11.5	87
30-35	30x)	"	105.5	.56	1.3	1.9	16.5	14.6	88
35-39½	80	TS	117.6	9.23	-	9.2	13.3	4.1	31
39½-40½	100	Shale	-	0	-	-	-	-	-
40½-41½	70	TS	(120)	19.00	-	19.0	13.3	-5.7	-43
41½-44	100	Shale	-	0	-	-	-	-	-
44-45	"	TS	(130)	15.95	-	16.0	13.0	-3.0	-23
45-48	"	Shale	-				-		
Avg.				3.01 (34%)	0.8 (9%)	3.8	8.9	5.1	57
Avg.(15-39½)				2.2 (18%)	1.6 (13%)	3.8	12.2	8.4	69

x) 5% core+25% cuttings.

Table 49

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C15.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-9	100	Soil	115.1	1.06	-	1.1	-	-1.1	-
9-15	"	TS & coke	112.8	0	4.2	4.2	12.2	8.0	66
15-20	"	"	123.6	0	5.8	5.8	7.8	3.0	38
20-25	80	"	126.8	0	3.2	3.2	9.6	6.4	67
25-30	80	"	121.2	0.12	3.9	4.0	13.5	9.5	70
30-35	90	"	115.0	0	5.7	5.7	16.0	10 .3	64
35-40	95	"	112.8	0	8.9	8.9	15.7	6.8	43
40-46½	85	"	107.3	1.35	9.1	10.5	15.0	4.5	30
46½-51	80	Soft shale	(110)	1.79	-	1.8	-	-1.8	-
51-55	100	TS	108.1	4.28	-	4.3	5.1	0.8	16
Avg.				0.80	4.0	4.8	9.2	4.2	47
				(9%)	(43%)				
Avg. (15-45)				0.25	6.2	6.4	12.9	6.5	50
				(2%)	(48%)				

Table 50

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C16.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-8	100	Soil	(120)	0.17	-	0.2	-	-0.2	-
8-10	90	TS	124.6	5.92	-	5.9	12.4	6.5	52
10-15	90	TS & coke	128.0	1.05	2.4	3.5	11.0	7.5	68
15-20	100	"	137.5	0.09	6.6	6.7	10.2	3.5	34
20-25	"	"	134.8	0.04	6.2	6.2	8.3	2.1	25
25-30	"	"	118.6	0.03	5.6	5.6	11.9	6.3	53
30-35	"	"	122.8	0.02	13.9	13.9	13.3	-0.6	- 5
35-40	"	"	113.8	0.04	15.2	15.2	16.0	0.8	5
40-42	"	"	124.3	0.11	14.3	14.4	16.0	1.6	10
42-49½	65	Shale	110.0	0.60	-	0.6	-	-0.6	-
49½-55	40	TS	112.5	6.26	-	6.3	9.8	3.5	36
Avg.				1.07	5.0	6.1	8.4	2.3	27
				(13%)	(60%)				
Avg. (15-42)				0.05	9.8	9.9	12.2	2.3	19

Table 51

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C17.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	(120)	0.38	0	0.4	-	-0.4	-
5-11	"	"	(120)	-	0	0	-	-	-
11-11½	"	TS - coke	141.7	-	2.8	2.8	11.1	8.3	75
11½-13	"	Soil	(120)	-	0	0	-	-	-
13-15	70	TS - coke	141.7	-	2.8	2.8	11.1	8.3	75
15-20	95	"	146.8	-	1.3	1.3	10.3	9.0	87
20-25	95	"	156.6	-	2.8	2.8	7.9	5.1	65
25-30	50	"	137.8	-	6.6	6.6	11.7	5.1	44
30-35	100	"	121.1	-	12.2	12.2	13.3	1.1	8
35-42	"	"	114.7	-	12.3	12.3	16.2	3.9	24
42-44	"	Shale & TS	116.9	-	0	0	4.0	4.0	100
44-48	"	Shale		-	0	0	-	-	-
48-50	30	TS	(120)	9.38	0	9.4	14.5	5.1	35.1
50-55	85	TS&Sand	113.9	1.50	0	1.5	7.0	5.5	79
Avg.				0.51 (7%)	3.8 (49%)	4.3	7.8	3.5	45
Avg.(15-45)				0	6.7 (60)	6.7	11.2	4.5	40

Table 52

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C18.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-10	100	Soil	(120)	0.42	0	0.4	-	-0.4	0
10-15	95	TS coke	128.1	0.38	0.4	0.8	11.2	10.4	93
15-20	95	" "	136.7	0	4.1	4.1	10.3	6.2	60
20-25	95	" "	132.5	0	4.4	4.4	7.7	3.3	43
25-30	50	" "	125.5	0	3.3	3.3	11.6	8.3	72
30-35	40	lost circ.	123.5	0	8.3	8.3	13.3	5.0	38
35-40	35	" "	113.8	0	8.4	8.4	16.2	7.8	48
40-45	15	" "	(115)	1.02	6.0	7.0	14.0	7.0	50
45-50	100	Shale		0	0	0	-	-	-
50-55	80	TS & Shale	119.4	7.33	0	7.3	11.6	4.3	37
Avg.				0.87	3.2	4.0	8.7	4.7	54
				(10%)	(37%)				
Avg.(15-45)				0.17	5.8	5.9	12.2	6.3	52
				(1%)	(48%)				

Table 53

<u>L9 POST-HEATING CORE ANALYSIS -CORE HOLE C19.</u>

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	(120)	3.8	0	3.8	0	-3.8	-
5-10	"	"	(120)	0.06	0	0.06	0	-0.1	-
13-14	"								
10-13	90	TS	148.2	1.73	0	1.7	11.1	9.4	85
14-15	100								
15-20	95	TS & coke	135.4	0	2.4	2.4	10.4	8.0	77
20-25	100	"	140.6	0	2.1	2.1	7.5	5.4	72
25-30	"	"	119.8	0	2.4	2.4	11.6	9.2	79
30-35	"	"	114.9	0	5.3	5.3	13.3	8.0	60
35-40	"	"	106.2	0	5.9	5.9	16.0	10.1	63
40-44	"	"	113.2	2.61	4.3	6.9	15.0	8.1	54
44-49	"	Shale	-	0	-	0	-	-	-
49-51	"	TS	(115)	0.13	0	0.1	15.2	15.1	99
51-55	"	Shale&Sand	(115)	4.0	0	4.0	-	- 4.0	-
Avg.				0.96 (12%)	1.96 (25%)	2.9	8.0	5.1	64
Avg. (15-45)				0.35 (3%)	3.6 (31%)	3.9	11.8	7.9	67

Table 54

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C20.

Depth	Recovery	Description	Density	Extr. Tar	Coke	Total	Original Tar	Loss	
ft			lb/ft^3	lb/ft^3		H-C	lb/ft^3	lb/ft^3	%
0-9½	100	Soil	-	0	-	0	-	-	-
9½-12½	"	TS	131.7	0.24	-	0.24	12.0	11.8	98
12½-15	"	Soil	-	0	-	0	-	-	-
15-19	"	TS-coke	142.4	0	3.7	3.7	10.7	7.0	65
19-20	"	Soil-coke	(120)	1.49	2.2	3.7	10.7	7.0	65
20-25	95	TS-coke	129.6	0	4.9	4.9	7.4	2.5	34
25-30	"	"	152.1	0	5.3	5.3	11.7	6.4	55
30-35	90	"	134.8	0	5.8	5.8	13.3	7.5	56
35-40	80	"	(125)	0	5.5	5.5	16.6	11.1	67
40-47	80	"	(125)	0	3.4	3.4	15.0	11.6	77
47-50½	100	Shale	-	0	-	-	-	-	-
50½-52	60	TS	122.9	14.16	-	14.2	15.0	0.8	5
52-55	90	TS & Shale	112.5	4.47	-	4.5	5.6	1.1	20
Avg.				0.67 (8%)	2.7 (31%)	3.4	8.7	5.3	61
Avg (15-45)				0.04 (0.3%)	4.7 (38%)	4.8	12.5	7.7	62

Table 55

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C21.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	(120)	1.55	-	1.6	-	-1.6	-
5-9½	"	"	(120)	.43	-	0.4	-	-0.4	-
9½-12	"	TS	121.2	2.18	-	2.2	12.4	10.2	82
12-15	"	TS & coke	122.2	1.80	2.4	4.2	12.5	8.3	66
15-20	"	"	125.3	-	3.3	3.3	11.6	8.3	72
20-25	90	"	126.1	-	3.4	3.4	11.2	7.8	70
25-30	100	"	122.4	0.06	6.5	6.6	11.4	4.8	42
30-35	"	"	125.1	.31	9.8	10.1	14.7	4.6	31
35-40	"	"	128.6	-	13.5	13.5	16.5	3.0	18
40-47	"	"	127.1	2.44	9.4	11.8	14.0	2.2	16
47-51	"	Shale	117	-	-	-	-	-	-
51-55	"	TS	147.6	8.83	-	8.8	-4.7	-4.7	-115
Avg.				1.36 (15%)	4.6 (49%)	6.0	9.3	3.3	35
Avg. (15-45)				0.47 (4%)	7.6 (58%)	8.1	13.2	5.1	39

Table 56

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C22.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	(120)	0.98	-	1.0	-	-1.0	-
7-10	"	TS	127.4	8.73	-	8.7	13.5	4.8	36
10-12	"	Sand	124.5	0.27	-	0.3	11.2	10.9	97
12-15	"	TS & coke	135.8	2.30	0	2.30	11.2	8.9	79
15-20	"	"	135.5	0.14	10.7	10.8	10.4	-0.4	- 4
20-23½	"	"	131.4	-	2.2	2.2	10.5	8.3	79
23½-30	80	" x)	(120)	1.31	2.9	4.2	12.8	8.6	67
30-35	100	"	(120)	0.71	0.9	1.6	15.6	14.0	90
35-40	90	"	106.9	0.97	6.4	7.4	16.1	8.7	54
40-42½	100	"	117.4	8.05	-	8.1	13.0	4.9	38
42½-47½	"	Shale	-	-	-	-	-	-	-
47½-51½	"	TS	145.0	6.55	-	6.6	6.7	0.1	1
51½-55	"	TS & Shale	113.1	3.19	-	3.2	3.5	+0.3	9
Avg.				2.10 (23%)	2.1 (23%)	4.22	9.1	4.9	54
Avg.(15-45)				1.26 (10%)	3.8 (31%)	15.1	12.1	7.0	58

x) Lost circulation at 24', core from 21½ to 25 feet was recovered as cuttings.

Table 57

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C23.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	122.0	0.41	-	0.4	-	-0.4	-
5-12	"	"	120.7	0.31	-	0.3	-	-0.3	-
12-15	"	TS&coke	124.7	0.60	1.0	1.6	11.0	9.4	85
15-20	"	"	141.1	-	1.1	1.1	8.0	6.9	86
20-25	"	"	114.2	-	0.8	0.8	9.1	8.3	91
25-30	"	"	(115)	-	1.4	1.4	15.0	13.6	91
30-35	90	"	115.2	-	12.1	12.1	13.7	1.6	12
35-40	100	"	116.3	-	2.8	2.8	15.5	12.7	82
40-42	90	Shale	104.6	0.10	6.5	6.6	-	-6.6	
42-45	90	"		-	-	-	-	-	-
Avg. (To 45')				0.14 (2%)	2.4 (32%)	2.5	7.5	5.0	67
Avg.(15-45)				0	3.5 (34%)	3.5	10.2	6.7	66

Table 58

L9- POST-HEATING CORE ANALYSIS - CORE HOLE C24.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-9	100	Soil	128.0	-	-	-	-	-	-
9-15	"	TS	(125)	1.79	-	1.8	10.2	8.4	82
15-20	"	TS & coke	127.8	1.67	1.3	3.8	6.3	3.3	52
20-25	95	"	133.6	-	2.7	2.7	7.7	5.0	65
25-31	100	"	111.0	0.11	2.7	2.8	15.1	12.3	81
31-37	"	"	117.5	9.98	-	10.0	13.9	3.9	28
37-38	"	TS	114.9	4.94	-	4.9	14.1	9.2	65
38-40½	"	Shale	-	-	-	-	-	-	-
40½-43	"	Shale & TS	132.0	6.05	-	6.0	6.0	0.0	0
43-50	"	TS	126.0	5.00	-	5.0	6.9	1.9	28
50-55	50	"	129.2	6.85	-	6.8	6.0	-0.8	-13
Avg.				3.07 (41%)	0.7 (9%)	3.8	7.5	3.7	49
Avg.(9-38)				2.9 (26%)	1.4 (13%)	4.3	11.0	6.7	61

Table 59

L9 POST - HEATING CORE ANALYSIS - CORE HOLE C26.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-10	100	Soil	126.8	-	-	-	-	-	-
10-12	"	TS	112.2	7.67	-	7.7	10.5	2.8	27
12-17½	"	TScrush-coke(125)		1.32	1.1	2.4	8.7	6.3	72
17½-20	"	TS coke	141.1	1.75	2.0	3.8	6.5	2.7	42
20-25	"	"	146.0	-	0.9	0.9	8.2	7.3	89
25-30	"	"	120.9	-	2.3	2.3	15.1	12.8	85
30-35	"	"	119.8	-	5.0	5.0	13.5	8.5	63
35-38½	"	"	115.4	-	5.3	5.3	15.1	9.8	65
38½-40½	"	Shale	121.5	-	-	-	-	-	-
40½-43	"	"	104.6	0.16	-	0.2	-	-0.2	-
43-48	"	TS	128.8	4.95	-	5.0	6.8	1.8	26
48-52	"	TS	127.8	8.18	-	8.2	7.0	-1.2	-17
52-55	50	Shale & TS	116.5	4.94	-	4.9	5.0	0.1	2
Avg.				1.81 (25%)	1.3 (18%)	3.1	7.3	4.2	58
Avg.(10-38½)				0.9 (8%)	2.5 (22%)	3.4	11.3	7.9	70

Table 60

L9 POST - HEATING CORE ANALYSIS - CORE HOLE C27.

Depth ft	Recovery	Description	Density lb/ft³	Extr. Tar lb/ft³	Coke	Total H-C	Original Tar lb/ft³	Loss lb/ft³	Loss %
0-8	100	Soil	130.1	1.89	-	1.89	-	-1.9	-
8-10	"	TS	120.9	10.22	-	10.22	13.0	2.8	22
10-12½	"	TS-crushed	(120)	1.87	-	1.87	11.0	9.1	83
12½-13½	"	TS	123.2	2.97	-	2.97	11.0	8.0	73
13½-14	"	TS-crushed	(120)	1.87	-	1.87	11.0	9.1	83
14-15	"	TS	123.2	2.97	-	2.97	11.0	8.0	73
15-20	90	TS & coke	127.8	-	1.7	1.7	10.4	8.7	84
20-25	100	"	119.2	-	2.4	2.4	10.1	7.7	76
25-30	"	"	116.9	-	3.3	3.3	13.2	9.9	75
30-35	"	"	118.5	-	5.0	5.0	15.2	10.2	67
35-40	"	"	112.5	1.18	3.6	4.8	16.2	11.4	70
40-43½	90	"	131.0	9.24	1.0	10.2	15.5	5.3	34
43½-48	100	Shale	-	-	-	-	-	-	-
48-48½	"	Sand	-	-	-	-	-	-	-
48½-53	"	TS	128.4	3.69	-	3.7	6.0	2.3	38
Avg.				1.99 (20%)	1.5 (15%)	3.5	10.0	6.5	65
Avg (15-45)				1.27 (10%)	2.8 (22%)	14.1	12.7	8.6	68

Table 61

L9 POST - HEATING CORE ANALYSIS - CORE HOLE C28.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	117.1	0.80	-	0.8	-	-0.8	-
7-10	"	TS	131.1	6.10	-	6.1	13.5	7.4	55
10-15	"	TS	132.8	7.16	-	7.2	10.9	3.7	34
15-20	"	TS & coke	130.2	0.72	2.5	3.3	10.8	7.5	69
20-25	"	"	125.3	-	2.4	2.4	11.0	8.6	78
25-30	95	"	122.9	-	2.9	2.9	12.5	9.6	77
30-35	100	"	122.2	-	2.6	2.6	15.4	12.8	83
35-40	"	"	117.5	-	6.6	6.6	16.1	9.5	59
40-46	"	"	120.0	4.78	2.6	7.4	16.1	8.7	54
46-50	75	Shale &TS	119.8	1.35	-	1.4	-	- 1.4	-
50-54½	100	TS	142.1	4.48	-	4.5	5.5	1.0	18
54½-55	100	Shale	-	-	-	-	-	-	-
Avg.				2.14	1.9	4.0	9.9	5.9	60
				(22%)	(19%)				
Avg. (15-45)				0.92	3.3	4.2	13.7	9.5	69
				(7%)	(24%)				

Table 62

L9 POST - HEATING CORE ANALYSIS - CORE HOLE C29.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-6½	100	Soil	117.2	0.57	-	0.6	-	-0.6	-
6½-10	"	TS	127.8	9.42	-	9.4	13.5	4.1	30
10-15	"	TS	134.8	6.54	0.1	6.6	10.6	4.0	38
15-20	"	TS & coke	136.8	1.95	3.6	5.5	11.0	5.5	50
20-25	"	"	132.0	-	3.0	3.0	11.3	8.3	73
25-30	"	"	125.0	-	3.0	3.0	12.0	9.0	75
30-35	"	"	120.5	-	3.3	3.3	15.6	12.3	79
35-40	"	"	116.3	-	8.8	8.8	16.3	7.5	46
40-45½	"	"	125.3	3.57	5.2	8.8	16.1	7.3	45
45½-50½	"	Shale		-	-	-	-	-	-
50½-55	"	TS	147.2	4.81	-	4.8	5.5	0.7	13
Avg.				2.19 (22%)	1.7 (17%)	3.9	9.9	6.0	61
Avg.(15-45)				0.92 (7%)	4.5 (33%)	5.4	13.7	8.3	61

Table 63

L9 POST - HEATING CORE ANALYSIS - CORE HOLE C30.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	126.0	0.33	-	0.3	-	-0.3	-
7-10	"	TS	134.7	10.75	-	10.7	13.5	2.8	21
10-15	"	TS & coke	135.1	5.04	1.2	6.2	10.6	4.4	42
15-20	"	"	129.0	-	3.2	3.2	11.0	7.8	71
20-25	95	"	131.9	-	2.8	2.8	11.4	8.6	75
25-30	100	"	129.2	-	9.2	9.2	11.9	2.7	23
30-35	"	"	127.9	-	12.2	12.2	15.6	3.4	22
35-40	"	"	124.1	-	16.5	16.5	16.0	-0.5	- 3
40-43½	"	"	132.9	-	10.9	10.9	16.1	5.2	32
43½-45	"	Shale	99.4	-	-	-	-	-	-
45-48½	"	"	-	-	-	-	-	-	-
48½-54	"	TS	148.6	4.83	-	4.8	5.5	0.7	13
54-55	"	TS & Shale	124.8	3.18	-	3.2	5.5	2.3	42
Avg.				1.63 (17%)	4.8 (51%)	6.4	9.4	3.0	32
Avg.(15-45)				0	8.6 (67%)	8.6	12.9	4.3	33

Table 64

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C31.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	108.3	-	-	-	-	-	-
7-10	"	Sand & TS	(120)	0.50	-	0.5	11.0	10.5	95
10-15	"	"	(120)	0.60	-	0.6	10.8	10.2	94
15-20	95	TS & coke	133.2	-	2.0	2.0	7.7	5.7	74
20-25	95	"	136.5	.07	4.1	4.2	9.0	4.8	53
25-30	100	"	(135)	.13	2.9	3.0	14.3	11.3	79
30-35	90	"	122.0	-	6.2	6.2	13.5	7.3	54
35-38	100	"	107.7	-	5.2	5.2	15.5	10.3	66
38-40	"	Shale	112.3	1.54	-	1.5	-	-1.5	-
40-50	65	Shale, sand & coke	108.1	.88	2.2	3.1	-	-3.1	-
50-55	30	Shale & TS	(110)	3.26	1.9	5.2	5.6	0.4	7
Avg.				0.61 (9%)	2.3 (33%)	2.9	7.0	4.1	59
Avg.(15-45)				0.28 (3%)	3.4 (38%)	3.7	9.0	5.3	59

Table 65

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C32.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-5	100	Soil	117.7	0	-	-	-	-	-
5-9	"	Soil & coke	(118)	0.92	2.9	3.8	-	-3.8	-
9-15	85	TS & coke	134.4	0	2.2	2.2	10.7	8.5	79
15-20	100	"	143.7	0	0.1	0.1	7.9	7.8	99
20-25	"	"	133.8	0	3.2	3.2	9.0	5.8	64
25-30	"	"	120.8	0	3.3	3.3	15.1	11.8	78
30-35	"	"	119.7	0	3.2	3.2	13.5	10.3	76
35-39½	"	"	116.3	0	3.9	3.9	15.5	11.6	75
39½-50	60	Shale	114.4	0.67	-	0.7	-	- 0.7	-
50-55	85	" & TS	119.4	5.99	-	6.0	5.0	- 1.0	-20
Avg.				0.74	2.4	3.1	7.0	3.9	56
				(11%)	(34%)				
Avg.(15-45)				0.12	2.2	2.3	9.9	7.6	77
				(1%)	(22%)				

Table 66

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C33.

Depth ft	Recovery	Description	Density lb/ft^3	Extr. Tar lb/ft^3	Coke	Total H-C	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-4½	100	Soil	93.5	0	0	0	0	0	-
4½-6	"	TS, crushed	(120)	3.19	-	3.2	10.6	7.4	70
6-11	"	" " & coke	(120)	0.53	1.7	2.2	10.7	8.5	89
11-15	"	TS & coke	124.2	0	3.1	3.1	10.6	7.5	71
15-20	"	"	146.0	0	0	-	7.8	7.8	100
20-25	"	"	140;6	0	1.6	1.6	9.0	7.4	82
25-30	"	"	119.4	0	3.4	3.4	15.1	11.7	77
30-35	"	"	(119)	0	4.8	4.8	13.5	8.7	64
35-38	"	"	118.3	0	6.3	6.3	15.5	9.2	59
38-40	"	Shale & TS	106.5	2.36	-	2.4	6.0	3.6	60
40-49½	"	Shale & coke	123.5	0.68	1.3	2.0	-	-0.7	-
49½-55	"	Shale & TS	119.9	5.65	-	5.7	6.0	0.3	5
Avg.				0.90 (12%)	1.9 (24%)	2.8	7.8	5.0	64
Avg. (15-45)				0.27 (3%)	2.5 (26%)	2.8	9.5	6.7	71

Table 67

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C34.

Depth ft	Recovery	Description	Density lb/ft³	Extr. Tar lb/ft³	Coke	Total H-C	Original Tar lb/ft³	Loss lb/ft³	Loss %
0-5	40	Soil	121.1	0.69	-	0.7	-	-0.7	-
5-10	100	"	(120)	0.76	-	0.8	-	-0.8	-
10-15	"	TS & coke	120.7	0.32	3.1	3.4	10.5	7.1	68
15-20	"	"	138.9	0	1.8	1.8	7.8	6.0	77
20-25	95	"	139.3	0	2.6	2.6	8.9	6.3	71
25-30	"	"	123.8	0	6.0	6.0	15.1	9.1	60
30-35	100	"	125.0	0	10.1	10.1	13.5	3.4	25
35-40 x)	"	"	114.1	0	8.0	8.0	15.5	7.5	48
40-42½	"	"	113.1	0	9.2	9.2	14.1	4.9	35
42½-45	90	Shale & coke	102.7	0.88	4.0	4.9	-	-4.9	-
45-50	100	Sand		0	-	-	-	-	-
50-55	50	Shale & TS	109.5	2.52	-	2.5	5.5	3.0	55
Avg.				0.43 (6%)	3.5 (46%)	3.9	7.6	3.7	49
Avg.(15-45)				0.07 (1%)	5.8 (51%)	5.9	11.3	5.4	48

x) crushed 35' - 37'.

Table 68

L9 POST-HEATING CORE ANALYSIS - CORE HOLE C35.

Depth ft	Recovery	Description	Density lb/ft^3	Tar lb/ft	Original Tar lb/ft^3	Loss lb/ft^3	Loss %
0-7	100	Soil	116.6	0.36	-	-0.4	-
7-10	"	TS	(120)	8.14	11.7	3.6	31
10-15	"	"	143.1	11.83	15.0	3.2	21
15-20	90	"	128.1	7.12	12.0	4.9	41
20-25	95	"	138.3	7.00	10.0	3.0	30
25-30	100	"	137.8	3.43	12.5	9.1	73
30-35	"	TS	(120)	2.30	15.5	13.2	85
35-40	"	"	116.6	11.92	16.5	4.6	28
40-45	"	"	120.6	13.82	14.4	0.6	4
45-47	"	"	141.0	10.01	13.0	3.0	23
47-50	"	Shale		-	-	-	-
50-55	"	Shale & TS	146.6	3.77	4.9	1.1	22
Avg.				6.42	10.3	3.9	38
Avg. (15-45)				7.60	13.5	5.9	44

No coke. Total H-C: Same as "tar".

Table 69

PRODUCTION TESTS - WELL B5-3.

Date	10.9	10.13	10.16	10.20
Pressure (mm Hg)	76	63	60	58
Gas (scf/day)	205	124	51	28
Oil (bbl/day)	0.032	0.020	0	0
Water "	0.103	0.072	0	0
Gas/Oil (Scf/bbl)	6400	6100	-	-
Water/Oil	3.2	3.5	-	-
Gravity (°API)	39	42	-	-

On October 9, after the above production test, the six wells surrounding B5-3 were shut in with the burners operating. The burner in B5-3 was shut off. Produmtion steadily declined until October 21, when the well was completely plugged. This well was unplugged on October 30 by injecting air into the gas casing.

Between October 17 and 21 the burner was started with 12,000 BTU/h.

The pressure in the shut off wells was about 100 mm Hg.

Nov.6,1958.

Table 70

PRODUCTION TESTS.

Well	B7-3	B4-10	B8-10	B1-10,2-9,10.
Date	10.8	10.16	10.16	10.24
Pressure (mm Hg)	75	59	59	42
Gas (scf/d)	440	83.3	10.3	560
Oil (b/d)	0.265	0.039	0.004	0.616
Water "	0.177	0.188	0.136	0.110
Gas/oil (Scf/b)	1660	2130	2520	910
Water/Oil	0.67	4.8	34	0.179
Gravity (°API)	31.3	26.7	-	28.6

Well	B9-6 to 10	B10-1 to 10	B6-7 to 10	B5-6 to 10
Date	9-19	9-19	9-30	10-3
Oil (b/d)	0.0141	0.00075	0.215	0.247
Water "	0.443	0.074	0.143	0.031
Water/Oil	31.4	99	0.67	0.13

Table 71

L9 PRODUCTION TESTS.

Wells	Date	Press (mmHg)	Oil (b/w-d)	Water (b/w-d)	Gas (scf/w-d)	GOR (scf/b)	WOR	Grav. °API
B1-1,2	11-1	39	0.139	0.235	206	1480	1.69	34.1
B1-2,2-2,3,4	11-24	40	0.283	0.096	229	810	0.34	29.8
B1-4,5,7,2-3,5	11-1	40	0.188	0.060	202	1072	0.32	31.9
Rows 1,2	11-20	41	0.026	0.064	65	2500	2.48	30.9
B2-3,5,7,9	11-5	46	0.181	0.118	342	1890	0.65	32.5
G22,24,26,28	11-4	45	0.260	0.098	456	1755	0.38	26.9
"	11-20	44	0.160	0.080	343	2140	0.50	28.6
B1-10,2-9,10	10-24	42	0.616	0.110	560	910	0.18	28.6
B2-7,8,9	11-24	40	0.284	0.070	445	1570	0.25	27.3
B3-1,6,7,8,4-1,3,5,8	11-13	56	(Rates too low to measure)					25.9
B3-9,10,4-9,10	11-13	56	0.116	0.443	226	1950	3.81	27.0
G41,43,49	11-24	45	0.152	0.121	296	1950	0.79	35.1
B5-1,6-2,3	11-18	56	0.290	0.297	305	1050	1.02	29.7
B5-5,6-4,5,7	11-18	56	0.238	0.182	321	1350	1.31	26.1
B5-8,9,10,6-9,10	11-18	56	0.153	0.119	193	1260	0.78	29.6
G61,63,65,67,69	11-5	58	0.047	0.046	149	3160	0.98	39.3
"	11-24	51	0.007	0.011	70	9550	1.55	40.8
G81,83,85,87,89	11-18	62	0.011	0.005	83	7300	0.42	27
G83,87	11-21	53	0.033	0.009	168	5090	0.27	31.5
B9-2,3,10-1,2	11-20	50	0.048	0.250	0	0	5.22	22.3
B9-5,6,7,10-5,6	11-24	-	0.140	0.286	148	1055	2.04	26.3
B9-10,10-9,10	11-13	-	0.071	0.841	144	2040	11.3	27.4
G92,94,96,98	11-21	52	0.007	0.017	36	5000	2.32	29.1
W22	11-24	45*	1.108	0.312	1470	1330	0.28	29.9
W28	11-26	62	0.472	0.320	1152	2440	0.68	31.5
W82	11-25	56	0.092	0.310	180	1960	3.37	27.7
W99	11-26	62	0.101	0.684	192	1900	6.77	24.4

*sampled at 63 mm Hg.

L9 PRODUCTION TESTS.

Jan.5.59.RH.

Table 72

L9 PRODUCTION TESTS, DECEMBER 1958.

Wells	Date	Press (mmHg)	Oil (b/w-d)	Water (b/w-d)	Gas (scf/w-d)	GOR (scf/b)	WOR	(Grav.) °API
B1-1,2	2	42	0.076	0.223	224	2960	2.94	32.3
B1-4,7	2	42	0.306	0.315	600	1960	1.03	29.1
B2-3,5,7,9	2	42	0.075	0.252	229	3070	3.38	27
B1-10,2-10	2	42	0.251	0.237	666	2650	0.95	29.2
G22,24,26,28	2	45	0.083	0.037	227	2720	0.45	29.0
B3-1,2,4-1,2	3	45	0.080	0.083	147	1840	1.10	31.2
B3-3,4,6,7,8,4-3,5,7	3	45	0.014	0.097	161	11350	6.80	27
B3-10,4-10	2	52	0.293	0.448	444	1515	1.53	28.0
B3-10,4-10	3	50	0.329	0.282	684	2080	0.86	28.9
G41,43,49	3	50	0.064	0.041	322	5050	0.64	34.6
B5-1,6-1	4	54	0.084	0.206	528	6280	2.45	40.9
B5-4,5,6-5,6	4	54	0.103	0.080	442	4290	0.77	28.5
B5-9,10,6-8,9,10	4	52	0.039	0.177	264	6810	2.28	31.8
G61,63,65,67,69	3	52	0.011	0.013	50	4410	1.16	37
B7-1	5	50*	0.183	0.719	739	4040	3.92	30.8
B7-6,7,8-4	5	50	0.132	0.556	497	3760	2.38	27.1
B7-9,10,8-8,10	4	56	0.156	0.201	443	2840	1.29	28.9
G83,87	4	54	0.035	0.035	150	4350	1.00	35.7
B9-1,3,10-1,2,3	6	47	0.055	0.077	73	1330	1.40	25.2
B9-6,7,10-5,6,7	5	54	0.038	0.169	60	1565	4.4	26
B9-9,10,10-8,9,10	5	-	0.075	0.202	35	470	2.71	23
G92,94,96,98	5	52	0.007	0.035	57	7630	4.73	27
W22	6	46	0.549	0.291	1540	2800	0.53	36.0
W28	6	39†	0.729	0.485	1733	2380	0.67	28.6
W82	5	54	Rates to low to sample					
W99	5	54	0.134	0.702	175	1305	5.24	25.7

* Sampled at 54 mm Hg   † Sampled at 52 mm Hg

Table 73

L9 PRODUCTION TESTS.

Wells	Date	Press. (mm)	Oil (b/d)	Water (b/d)	Gas (scf/d)	GOR (scf/b)	WOR	Grav. °API
B1-3	12-31	50	0.338	0.602	557	1650	1.78	29.9
B1-5,2-5	12-31	50	0.378	0.497	650	1720	1.32	27.9
B1-8,10	12-31	50	0.387	0.463	520	1342	1.20	26.6
G22,24,26,28	12-31	53	0.152	0.082	420	2780	0.54	24.4
B3-1,2,3,4-1	1-2	59	0.0185	0.190	78	4210	10.3	24.1
B3-6,7,4-3,5	1-2	59	0.0286	0.0829	217	7600	2.90	30.2
B3-10,4-10	1-2	59	0.126	0.584	315	2500	4.62	25.8
G41,43,49	12-31	59	0.0720	0.0782	255	3540	1.09	27
B5-1,6-1	1-2	58	0.170	0.209	512	3020	1.23	31.2
B5-4,5,6-3,5,6	1-2	58	0.0273	0.0955	126	4620	3.50	28
B5-8,9,10,6-7,8,9,10	1-2	58	0.0366	0.0867	171	4680	2.31	29.7
G61,63,65,67,69	1-2	60	0.0089	0.0274	35	3900	3.10	33.3
B8-1	1-3	60	0.203	0.464	96	474	2.28	29.4
B7-1,8-1	1-21	68	0.0323	0.478	66	2040	14.8	24.5
B7-6,8-5	1-3	58	0.0860	0.557	390	4530	6.47	27
B7-5,6,8-4,5,6	1-21	68	0.0346	0.317	130	3760	9.16	25.2
B7-7,8,9,8-8,9,10	1-3	58	0.0369	0.157	267	7250	4.24	24.5
B7-9,10,8-7,8,9,10	1-21	68	0.0372	0.208	162	4350	5.60	23.1
G83,87	1-3	57	(Very low rate)				2.90	28
B9-1,2,10-1,2,3	1-6	57	0.0550	0.260	52	943	4.72	26
B9-1,10-1,2,3	1-21	66	0.0206	0.200	46	2240	9.70	23.1
B9-5,10-4,5,6	1-6	57	0.0739	0.392	151	2040	5.31	27.4
B9-4,5,10-4,5,6	1-21	66	0.0552	0.242	43	782	4.37	22.7
B9-9,10,10-8,9,10	1-6	57	0.141	0.456	215	1525	2.91	26
B9-10,10-8,10	1-21	66	0.125	0.438	170	1360	3.50	21.5
G92,94,96,98	1-3	60	(No production)					
W39	12-31	53x)	0.409	0.584	1056	2580	1.43	24.9
W22	12-31	57	0.238	0.201	737	3100	0.844	27
W99	1-3	60	0.174	0.579	432	2480	3.32	27
W82	1-3	60	(No production)					

x) Sampled at 75 mm Hg.

Table 74

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 1 and 2.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
2.25	0	10.5				23° API oil at 25psig. A f w gallons came up around Bl-6.
	15					Water production started.
2.26	25		1 gall/min.heated to 150°F.			
	40					Oil production started.
3.3	140		0.5 gall/min.not heated.			
3.12	360		Shut off.			
3.17	485		1.5 gall/min.	15	P1	The burners had been off 6 hrs after 477-483 hrs.
3.20	550		3 -"-			
3.27	715	4.8	3 times a day, 10 min. each with gas wells shut off.			Injected during oil circulatio
3.31	820		4 times a day, 15 min. each with gas wells shut off.			

Table 74 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 1 and 2.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
4.1	840					V10 plugged by tar
4.6	960		Shut off.			
4.11	1080			8	P1	V10 plugged by tar. Press. increased to 13 psig why P-line was opened to atm for 2 hours.
	1085	2.5	3 gall/min.			Also 20 ml Antifoam 200.
	1090	7.5				Inj. during oil circ.
4.15	1180		2 times a day,30 min. each with gas wells shut off.			
4.17	1220		2 times a day, 1hr each with gas wells shut off.	4	P1	
4.18	1250		Continous circ.			Treater and oil line to oil tanks plugged.
4.25	1420			11	P1	
4.26	1440			8		
4.29	1510			11	P1	
4.30	1540	1.5				

Table 74 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 1 and 2.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
5.2	1580			1		
5.3	1610	1.0		13	P1	Some of the tar production wa led to V14.
5.7	1700			3		
5.8	1730	7.0				Accidentally injected when ga condensor became plugged.
5.9	1750			2		
5.10	1775			4		
5.11	1800		Oil too heavy to circ. Diesel oil circulated.	4		V10 plugged. Production to su
5.13	1850			2		
5.14	1874			2		Production to treater.
5.15	1900			2		
5.16	1900			2		
5.17	1940					Gas condensor plugged. Product to sump.

Table 74 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 1 and 2.

Dat	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
5.19	1990			2		
5.21	2042					Production to treater.
5.27	2190		Diesel oil circ. Shut off.	1		
5.28	2210			1		

Table 75

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 3 and 4.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
2.25	0	9.5				Also 300 ml Antifoam A 23 ^{o}AP oil at 25 psig. A pint of oi came up through W39, thus at 50 ft. A few gallons oil cam up around B3-7,4-6.
	15					Water production started.
2.26	25		1 gall/min. heated to 150°F.			
	40					Oil production started.
3.3	140		0.5 gall/min. not heated.			
3.12	360		Shut off.			
3.17	485		1.5 gall/min.	15	P2	The burners had been off 6 hc after 477-483 hours.
3.20	550		3 -"-			
3.27	715	4.8	3 times a day, 10 min. each with gas wells shut off.			Accidentally inj. during oil
3.31	820		4 times a day, 15 min. each with gas wells shut off.			

Table 75 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 3 and 4.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
4.1	840					V10 plugged.
4.6	960		Shut off.			
4.11	1080			6	P2	V10 also plugged.
4.15	1180		2 times a day,30 min. each.			
4.18	1250			6	P2	Also treater and oil line t tanks plugged.
4.20	1300			6	P2	
4.22	1340			4	P2	
4.23	1370				P2	
4.27	1460				P2	
4.28	1490	3.0				Also 150 ml Antifoam A.
5.1	1560			1		
5.2	1580			1		
5.4	1630			4		
5.7	1700			3		

Table 75 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 3 and 4.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
5.8	1730	6				Accidentally injected when gas condensor became plugge
5.9	1750			1		
5.10	1780			4		
5.11	1800		Oil too heavy to circ. Diesel oil circulated.	4		
5.13	1850			2		V10 plugged.Production to s
5.14	1875			7		Production to treater.
5.15	1900			1		
5.16	1920			1		
5.17	1940					Gas condensor plugged.Prod. to sump.
5.21	2042					Production to treater.
5.23	2090			1		
5.25	2140			1		
5.26	2160			1		
5.27	2190		Diesel oil circ.shut off.	2		
5.28	2210			1		

Table 76

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 5 and 6.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
3.18	506	9.5				Also 800 ml tretolite M29.23 oil at 25 psig. 1 bbl oil cam up through W56.
3.19	525	5.2	3 gall/min.			Accidentally injected. P3 was off at the down stream end wh oil circulation was started.
3.27	715	4.8	3 times a day, 10 min. each with gas wells shut off.			Accidentally injected during circulation of oil.
3.31	820		4 times a day, 15 min. each with gas wells shut off.			
4.6	960		Shut off.			
4.16	1200		5 min. each day.			
5.7	1700			2		
5.8	1730	6.0			P3	Accidentally injected when ga condensor became plugged.
5.9	1750			2		
5.10	1780			5		
5.11	1800		Shut off.	5	P3	
5.13	1850			4		

Table 76 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 5 and 6.

Dat	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
5.14	1875			6		
5.15	1900			2		
5.23	2090			2		

Table 77

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 7 and 8.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
3.18	506	8.8				Also 240 ml Antifoam A23°API oil at 25 psig. 4 bbls oil came up through W99 and 0.5 bbl through W82.
3.19	525	5.2	3 gall/min.			Accidentally injected. P4 wa shut off at the down stream end when oil circulation was started.
3.27	715	4.8	3 times a day,10 min. each with gas wells shut off.			Accidentally injected during circulation of oil.
3.31	820		4 times a day,15 min. each with gas wells shut off.			
4.6	960		Shut off.			
4.16	1195		5 min. each day.			
5.7	1700			2		
5.8	1730	6.0				Accidentally injected when g condensor became plugged.
5.10	1780			5		
5.11	1800		Shut off.	6		
5.13	1850			9		
5.14	1875			6		

Table 77 (cont)

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 7 and 8.

Date	Hours from start	Oil injected Total Bbls	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
5.15	1900			3		
5.16	1920			3		
5.23	2090			5		
5.25	2140			6		
5.26	2160			3		
5.27	2190			8		
5.28	2210			1		

Table 78

OIL INJECTION AND TAR PRODUCTION IN L9.

Rows 9 and 10.

Date	Hours from start	Oil injected Total Gallons Bbls Per Gas Well	Oil Circulation in Main P-line	Plugged Number of ½" P-lines	P-lines Main P-line	Remarks
3.28	740	5.8(Row 9) 24				22° API oil at 25 psig.
3.31	820		4 times a day, 15 min. each with gas wells shut off.			
4.6	960		Shut off.			
4.16	1195		5 min. each day.			
5.10	1780			2		
5.11	1800		Shut off	2		
5.13	1850			1(Row 10)		
5.14	1875			2 "		
5.15	1900			2(1Row 10,1)		
5.19	1990			2		
5.25	2140			3		

Table 79

GROUND WATER PUMPED UP FROM L9.

Date	Wells	Water Bbls/day	Cum.	Remarks
1.8-1.13	B5-6	100	500	A piston pump was placed in the burner hole B5-6 before the casing was set. The lowering of the water level is shown on Figure 156.
1.20-2.24	W22,39 W56,82 W99	110	4500	
2.25-4.10	-"-	60	7000	W22,39,82 plugged by tar.
4.11-5.14	W56,99 W510	30	8000	W56 plugged by tar.
5.15-5.30	W99,510	15	8200	W89 plugged by tar.
6.1-6.20	W15,51 W510	25	8700	
6.21-7.27	W15,51 W105,510	30	9800	W51 plugged by tar. W105 dry most of the time.
7.28-9.22	W15,110 W210,510 W810,1010	75	14000	W15 plugged by tar. W1010 dry most of the time. 70 % of the water came from W110,210. Temp. of water: 100°, 75°, 85°, 80°, 100°, 150°F in W15,110,210,510,810, 1010 resp.
9.23-10.31	W110,210 W510,810 W107	90	17400	W107 dry most of the time. 75 % from W110,210 and 15 % of the water from W510. Temp. of water: 85°, 125°, 100°, 115°, 150°F resp.
11.1-11.30	W110,210 W510,810 W107	47	18800	W810 plugged by tar. W107 dry most of the time.
12.1-12.31	W110,210	39	20000	
1959				
1.1-1.18	W110,210 W510	17	20300	W110,210 plugged by tar Oil in W510.

Table 80

PRESSURES IN L9 P-LINES.

	Pressure in Psig at														
Date	S1	E1	V10	P1	B2-8	P6	P7	P2	B4-10	P3	B6-8	P4	B8-10	P5	B10-7
8.22.				1.26				1.60		1.66		1.70		1.72	
9.27				1.26				1.61		1.67		1.70		1.72	
9.30	0.70		1.34												
10.1	Flare moved.														
10.2	0.14	1.07		1.08				1.37		1.49		1.51		1.55	
10.5	0.12	0.74	1.05	1.10			1.37	1.37		1.47		1.49		1.49	
10.6				1.31		1.37									
10.9	0.11	0.87	1.12	1.30		1.33	1.37	1.39		1.43		1.45		1.45	
10.10	Condensors E1 coupled parallel.														
		0.48	0.99												
10.13	0.16	0.37	0.77	0.79	1.04	1.00	1.08	1.10	1.23	1.16	1.23	1.23	1.27	1.23	1.29
	3-way valve between V10 and E1 bypassed.														
10.14		0.43	0.70												
10.20	0.18	0.35	0.62	0.89				1.05		1.14		1.14		1.16	
10.25	0.16	0.37	0.62	0.89	0.91		0.97	1.01	1.04	1.04	1.06	1.10	1.12	1.11	1.14
10.27				0.91				1.04		1.08		1.12		1.16	

Table 81

POST-HEATING CORE DATA
PRODUCTION FROM INSIDE AREAS
(15-45' Interval)

	1	2	3
Located near	B6-3	B4-5	B7-6
Core holes	C16, 17, 18 19, 20	C22, 27, 28 29,30	C23, 31, 32 33,34
Original tar	2,560 lbs	2,886 lbs	2,120 lbs
" "	11.8 lb/ft^3	13.3 lb/ft^3	9.8 lb/ft^3
" " (4° API)	7.02 bbl	7.91 bbl	5.81 bbl
Residual hydrocarbon	1123 lbs	984 lbs	658 lbs
Produced hydrocarbon	1437 lbs	1902 lbs	1462 lbs
Wt. % Produced	56%	66%	69%
Oil Produced[1]	1105 lbs	1465 lbs	1125 lbs
" " (Wt. %)	43%	51%	53%
" " (27° API)[2]	3.55 bbl	4.72 bbl	3.62 bbl
Volume % Produced as Oil	51%	60%	62%

1 Assumed gas/oil ratio of 0.3 by weight.
2 The average oil gravity during the test was 27.4° API.

UNION OIL COMPANY OF CALIFORNIA

RESEARCH DEPARTMENT

BREA, CALIFORNIA

JOHN E. SHERBORNE
MANAGER
PRODUCTION RESEARCH DIVISION

July 9, 1959

JES-100

Mr. M. F. Westfall
Husky Oil Company
P. O. Box 380
Cody, Wyoming

Dear Wes:

FINAL REPORT - H-S-U EXPERIMENT

In accordance with discussions between Bob Helander, Bill Shirley and Bengt Persson, I am forwarding one copy of each of the two volumes of the final report on H-S-U Santa Cruz experiment to you, to Bill Shirley and to Bengt Persson. The remaining copies will be sent out within a few days when we have had a chance to assemble them. It is our understanding that Bengt and Bill were in need of copies as soon as they could possibly be provided.

Very truly yours,

ORIGINAL SIGNED BY
JOHN E. SHERBORNE

JES:vb
enc.

cc/w W. J. Shirley
Bengt Persson

CARBON COPY

Komplement till rapporten

"Field test of the LINS method for the recovery of oil from tar sand

Santa Cruz, California".

Värmebalans av L9 samt producerad gasmängd och erforderlig värmemängd för tjärsand av olika tjärhalter.

På sid. 12, tabell 20 och figur 97 visas den totala värmebalansen för 100-håls försöket L 9, beräknat på kalorimetriska värmevärden. Härav framgår att endast 13 % av värmet användes för upphettning av det till pyrolystemperatur uppvärmda området och att de vertikala värmeförlusterna utgjordes av 42 %. Återstoden 45 % utgjordes av produktionens fysikaliska värme framför allt vattenånga och förluster till fältets sidor.

Av stort intresse är hur värmebalansen blir i ett stort fält och framför allt om den producerade okondenserbara gasens värmeinnehåll är tillräcklig för pyrolysens genomförande, eller med andra ord om metoden kan bli termiskt självförsörjande med olja som enda slutprodukt.

För att få en uppfattning om de verkliga olje-och gasutbytena inuti L 9 borrades och analyserades tjärsanden och tjärsandskoksen inom tre områden, som beskrives på sid. 15-17, figur 110, 145-147 och tabell 81. Ur dessa data samt ur gasanalysen, tabell 22 har nedanstående värmebalanser uträknats, varvid följande effektiva värmevärden användes för tjären, oljan och restgasen (rågas exkl. gasbensin och svavelväte): 17.100 BTU/lb, 18.200 BTU/lb resp. 826 BTU/Scu.ft.

Område	1		2		3	
	10^6 BTU	%	10^6 BTU	%	10^6 BTU	%
Tjärsandens v.v.	43,8	100	49,5	100	36,2	100
Prodekternas "						
Olja	20,1	46,0	26,7	54,0	20,5	56,6
Gasbensin	0,2	0,5	0,3	0,6	0,2	0,6
H_2S i rågas	0,4	0,9	0,5	1,0	0,4	1,1
Restgas	5,5	12,6	7,3	14,7	5,6	15,5
Koks	17,6	40,1	14,7	29,7	9,5	26,2
	43,8	100	49,5	100	36,2	100

Medelvärdet av dessa tre områden ger följande värmebalans för L 9:

Olja	52,2 % av tjärans värmevärde
Gasbensin	0,6
H_2S i rågas	1,0
Restgas	14,3
Koks	31,9
	100,0

Gasbensinen och svavelvätet i rågasen har redovisats för sig, då gasbensinen bör avlägsnas och svavelvätet måste avlägsnas för att restgasen skall kunna användas i brännarna. För att ett tjärsand in-situ fält skall vara självförsörjande på gas till brännarna, får alltså ej mer gas användas, än att dess totala effektiva värmevärde motsvarar 14,3 % av tjärsandens effektiva värmevärde. Detta kommer då att bero på tjärhalten i tjärsanden. Därför har följande beräkningar av erforderlig värmemängd utförts med utgång från $\frac{1}{171}$ lb tjära, som har ett värmevärde av 100 BTU. Det antages att tjärsandens vattenhalt är 1 % och att värmeförlusterna är 40 % av det totalt tillförda värmet.

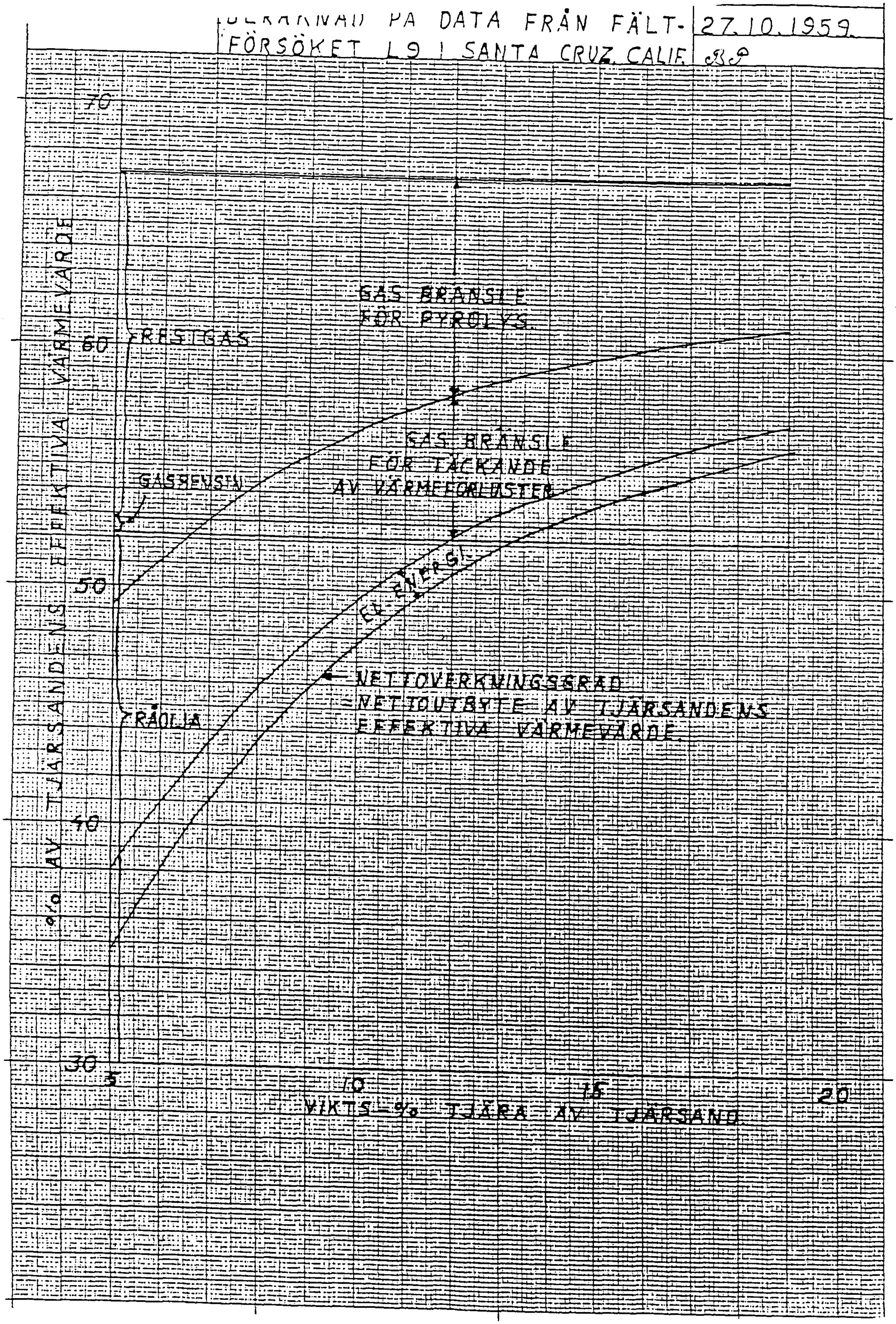
Tjärhalt, vikts %	8	10	12	14	16
Tjärsand, lb	0,0731	0,0585	0,0489	0,0419	0,0366
Spec. värme, BTU/lb, °F	0,249	0,255	0,260	0,266	0,271
Erforderligt värme för pyrolys, BTU	12,7	10,5	8,9	7,8	6,95
Värmeförluster, BTU	8,5	7,0	5,9	5,2	4,65
Totalt erforderligt värme, BTU	21,2	17,5	14,8	13,0	11,6
Tillkommer el.energi för luftkompressorer och arbetsmaskiner	2,1	1,8	1,5	1,3	1,2
Termisk nettoverkningsgrad = värmevärdet av olja + gasbensin + + restgas minus tillsatt gasbränsle + el. energi	43,8	47,8	50,8	52,8	54,3

I diagram 1 har dessa data sammanförts som funktion av tjärhalten i tjärsand. Dessutom har angivits det procentuella effektiva värmevärdet av produkterna råolja, gasbensin och restgas (= rågas exkl. gasbensin och svavelväte), som erhölls från värmebalansen i L 9. Denna är oberoende av tjärhalten, om det antages att tjärans kvalitet ej ändras med tjärhalten. Svavelvätets värmevärde har ej medtagits, då en framställning av ex. svavel troligen ej är av ekonomiskt intresse.

Av diagrammet framgår bl.a. att LINS-metoden med antagna värmeförluster blir självförsörjande på gasbränsle vid en tjärhalt av 12,5 % då den termiska nettoverkningsgraden är 51,4 %. Stora delar av tjärsandsfyndigheten i Athabasca, Canada innehåller denna tjärmängd.

Närkes Kvarntorp den 27.10.59.

Bengt Persson


BERÄKNAD PÅ DATA FRÅN FÄLT-
FÖRSÖKET L9 I SANTA CRUZ, CALIF.
27.10.1959.
70
60
50
40
30
% AV TJÄRSANDENS EFFEKTIVA VÄRMEVÄRDE
RESTGAS
GASBENSIN
RÅOLJA
GAS BRÄNSLE
FÖR PYROLYS.
GAS BRÄNSLE
FÖR TÄCKANDE
AV VÄRMEFÖRLUSTER
EL ENERGI
NETTOVERKNINGSGRAD
=NETTOUTBYTE AV TJÄRSANDENS
EFFEKTIVA VÄRMEVÄRDE.
5
10
15
20
VIKTS-% TJÄRA AV TJÄRSAND